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INCREASING THE RECOVERY OF PETROLEUM

INCREASING THE RECOVERY OF PETROLEUM

BY

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IN TWO VOLUMES

VOLUME II

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CHAPTER XV

THE AIR OR GAS LIFT

In General.—According to the Patent Office records, the first ideas along the line of using introduced gas or air as a lifting medium in oil wells occurred in the eighties. Judging, then, from the period of time at which the statement was written, it would indicate that the general idea of gas-lift methods involving the use of compressors is practically as old as the oil-producing industry.

Pennington[1] stated:

"From the earliest patents, it seems that Dr. Pohle was the inventor of the air lift, using it first for dewatering mines at Tombstone, Ariz., in and prior to 1886. A contemporary was John Obear, also a scientist, and a developer of the divided bubble principles. The Pohle patents were acquired by a compressor builder and the air lift was exploited under these for many years, successfully."

"The first oil field of the Gulf coast—Spindle Top—owed its huge sustained production to air, beginning in 1901, and air has been in continuous use for 26 years on the Gulf coast as a consequence, for in no other way can as large volumes of liquid be obtained from such a small diameter hole."

"The pioneers at Spindle Top were spurred on by these large recoveries and the old Spindle Top Power Company built a large plant, with 'air for hire.' Sour Lake followed, then Batson's Prairie, then Jennings, La., at the Evangeline, or Mamou field, where the largest air plants in the world were operated. Humble followed, in 1904, and since then every Gulf coast field has had its air period."

"Individual operators own these plants. In the earlier days, much air was sold at so much per well per day, or a well was blown for a percentage of the oil—the percentage being based upon production per well and ranging from 10 per cent in a large well, say 7,500 barrels, up to 40 per cent in a small well of, say, 250 barrels production."

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[1] PENNINGTON, HARRY, Lift Efficiency Depends upon Skill in Design and Operation, *Oil Weekly*, p. 41*ff*., Aug. 19, 1927.

"These plants were steam driven, the make of compressor being the Ingersoll-Sergeant, Rand, Leyner, and Laidlow."

The gas lift is simply a modified form of the air lift which has been used for many years in raising water from wells. The gas lift differs from the air lift in that natural gas is used as the lifting medium instead of air.

One of the chief reasons for the preferred use of gas instead of air is that it makes possible the saving and recovery of natural gasoline which would otherwise be waste if compression were depended upon for gasoline extraction, because the air-gasoline vapor mixture can and is being handled with due precaution, by the absorber type of gasoline extraction plant. Another reason for using gas instead of air is that it makes possible the saving of such natural gas as accompanies the oil. Gas has a further advantage of not oxidizing or corroding the casing and tubing as air does, especially in the presence of sulphur.

In general, it should be understood that the use of an air or gas lift is primarily to increase present production. In most cases, it merely displaces the inefficient pumping equipment with a cheaper operating and less troublesome means of producing the available oil. It is also useful, if installed early enough, to keep a well flowing, which, otherwise, would normally be put to pumping. None of its principles would tend to increase the ultimate production by causing trapped oil to be produced, nor would it tend to restore depleted pressure in any part of a sand not immediately adjacent to the well hole. The only phase of the principles of operation that can be considered as increasing ultimate production is the circumstance that, by supplying some of the energy needed for present production, it conserves instead of draws away the energy of the dissolved gas in the oil distant from the well, and leaves this energy available for future production. It merely energizes a column of fluid which has already entered the well, thus supplying energy which this particular oil has, probably, given up to flow the oil which was produced at some prior time.

Replacing or, at least, threatening to replace the pumping apparatus which has held sway since the inception of oil well drilling, this system of production commands immeasurable attention from the producers. The gas lift is able to raise more fluid from a well than can any kind of pump. Wells pumping 300 or 400 bbl. daily have been caused to produce more than 1,000 bbl. per day by the gas lift without injury to the wells.

The gas lift is adaptable to a well under most conditions in that period of its productive life when it is about ready to cease flowing and before it has reached the point where the pump can remove all the fluid that enters into the hole from the sands. This period will not be the same for all wells; likewise, in some wells it will last considerably longer than in others. The greatest waste of gas occurs when the well is flowing by its own gas pressure. There are many wells that would undoubtedly flow much better and more efficiently if they were operated by the gas lift instead of being allowed to flow by their own pressure.

Exact information as to performance of the gas lift, from the mechanical engineering standpoint, is difficult to obtain. There are now several hundred wells producing in California fields by means of the gas lift, and a survey of results shows that the gas lift has increased production at these wells by approximately 60 per cent. Similar or even larger figures describe results in mid-continent fields. Such an increase in output of oil is so satisfactory, from the standpoint of the average oil producer, as to not encourage investigation looking to more efficient operation.

One writer stated: "If there ever was a mechanical problem based upon empirical data, it is the air lift; there are so many variables, obtained accurately in the field only with practice, that formulæ will not be discussed except in a general way, for the writer finds that there are far more incorrect than correct conclusions drawn because of incorrect premises; conditions of service were not accurately obtained and computed results did not agree with actual results and conclusions."

There are already a sufficient number of production records to prove beyond any question of doubt that the gas lift is a success under favorable conditions. These conditions will usually be found in wells which are still flowing, or have just passed from the status of a flowing well to a pumper, or in wells where there is a reasonable fluid head. It should be easy to rejuvenate such producers, the bigger the well or the higher the fluid level the greater the increase should be. If wells are comparatively new and are good candidates for the gas lift and have not been equipped for pumping, they should show a substantial saving in the operating cost and the recovery of more oil on the gas lift than by pumping.

Engineers are virtually agreed that the gas-air system as installed and operated so extensively at this time can do no harm to the normal oil-bearing formation. Many engineers and operators agree that the pay horizon is more completely drained and greater ultimate recovery is secured by gas-lift methods than by pumping. It is certain that the flush production is drained in a shorter period and, with larger production thus secured, lifting costs are greatly reduced. Labor is reduced and pumping equipment is also reduced, although often left intact as auxiliary equipment. One of the greatest advantages of the gas-lift system of production is that of conservation of the gas. This gas, in addition to being conserved, is used as a carrying medium for gasoline which is stripped from the gas by the absorption or compression plant when it emerges from the well enriched through its contact with the oil. The application of air or gas lift permits better control of production of either water, gas, or oil.

Concerning the ultimate yield of a well as affected by air or gas lift practice, Mr. McLaughlin says:

"The success of the gas lift at various wells has upset some theories as to the rate of decline of production. It has not yet been determined what rule or theory will serve in wells which are susceptible to the use of the gas lift. The writer assumed two years ago, when first describing this feature, that the gas lift would merely make up the difference in oil produced between the amount which the pump could take out and the theoretical amount shown by a regular decline curve. However, it has been found in actual practice that instead of declining, some wells hold up their production at a practically constant rate for almost two years."

Pierce and Lewis,[1] in their paper presented at the Fort Worth meeting of the Petroleum Division, A.I.M.M.E., in October, 1927, made the following statements in regard to the purposes and practical limitations of the application:

"A review of the conditions to which the air lift has been applied since its introduction a few years ago will disclose that in many instances the primary consideration was to increase the daily production to the greatest possible extent regardless of all else. This is well illustrated at Seminole, where almost the only gage of efficiency under the highly competitive conditions there was the increase in daily production.

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[1] Pierce, H. R., and J. O. Lewis, Principles of the Air-gas Lift as Applied to Oil Production, *Petroleum Development and Technology*, p. 19, 1927.

"A second consideration was for a cheaper method of lifting the oil—both as to installation and operating costs.

"A third consideration was that in the very deep and crooked rotary holes that have been drilled in recent years, it was often unpractical and sometimes even impossible to use the old deep well plunger pump. This problem was the chief reason for the revival of the air lift in California."

"The fourth purpose is the use of the air lift as a means of increasing oil recovery as distinct from oil production. This results in a consideration of the effect of the back pressure caused by the air lift upon the expulsion from of the oil sand as measured by the gas-oil ratio, though as pointed out in the following pages, the ratio of volumes of gas to oil alone is not a correct criterion of measuring recovery efficiency."

"In considering these four main ends sought, it is obvious that they will not always be reconcilable and that the design and operation of a gas lift will differ with the different standards of efficiency. Of course, there will not always be a clear distinction between the ends sought, which often will be a combination of two or more factors, but always the final end will be what the operator thinks the most profitable manner of operation under the existing circumstances. It will be the problem of the engineer to work out and then convince the operator as to what the most profitable manner of operation will be, but to accomplish these purposes the engineer must be well fortified with the data which will enable him to design and operate his apparatus so as to fit the specific need most satisfactorily."

"In working out these problems the engineer will be faced usually with very definite practical limitations. For example, in the use of tapered tubing, the engineer will be limited to the size of the casing and he will be unable to use the graduations of flow pipe which would otherwise give the best results for a well to which the air lift is being applied."

"There will also be many other limitations, such as, the back pressure, the occurrence of water with the oil, and the emulsibility of the oil with the water, the size of the well equipment already on the ground, the relation of the air lift to gasoline extraction, the rock pressure and natural gas volume, whether or not the lift can be made continuous or intermittent, and many other factors which need not be mentioned here, as our primary purpose is illustrative and not enumerative."

"But the main point is that theory must finally be adapted to the practical needs and what the engineers need are guiding principles and accurately gathered and analyzed data, which will enable the design of the proper installation with the least delay and the least necessity for experimentation."

The advantages and disadvantages of the lift as listed by one writer are:

ADVANTAGES

Capacity, greater than any other known method.
Continuity of operation.
Cleans wells of sands and muck.
Low maintenance cost.
No working parts in well.
Central plant operation.
Greater daily recovery.
Greater ultimate recovery percentage.
Eliminates hazards of rod and tubing pulling, cleaning operations, and of swabbing.

DISADVANTAGES

Cost of installation.
Emulsification of oil when well makes water.
Corrosion of casing and well piping when oil and gas contain H_2S.
Paraffin trouble.

At this point, attention should be called to the patent situation. Lawrence E. Smith[1] stated in an article that patent 1,102,152 was issued June 30, 1914, and is owned by the firm of Jones-McLaughlin, Inc., of Los Angeles. A number of California companies operate as licensees under the above patent; some of the mid-continent operators were notified by the above firm that the use of the lift without license was an infringement. The article went on to state that the attorneys of the Mid-Continent operators were meeting to consider the situation.

Apparently, the Jones-McLaughlin firm sued the Amerada Petroleum Corporation in July, 1927, but nothing further is known, at the present time, as to the outcome of this test case.

Theory in General.—If it is wished to induce the fluid inside the flow pipe to rise higher than the fluid outside the pipe, it can be done by reducing the weight, or, more correctly, the density of the column of fluid as a whole contained within the pipe; then the greater relative weight of the fluid, or, what amounts to the same thing, an artificially supplied pressure outside the pipe, will act to force the lighter column of fluid upward. The simplest way to lighten the column of fluid in the pipe would seem to be to mix air or gas with it, and this the so-called "air lift" does, and it is practically all that it does, while gravity does the rest. Hereafter the use of the word "air" will refer likewise to "gas," these being interchangeable in this discussion.

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[1] *Nat. Petroleum News*, Apr. 6, 1927.

The diffusion of the air through the column of fluid elongates the column upward, but does not yet lighten it as a whole. The air might go on mixing with and diluting the fluid and gradually working its way up through it and, finally, if the pipe was long enough, the air would escape at the top of the column as fast as it was admitted at the bottom, but still there would be no "lifting" of the fluid by this operation alone. This gradual working of its way up through the fluid which the air thus does in the stationary column goes on also, but not so rapidly, when the column is moving and when the lift is in full operation, this constituting the "slippage" which seems to be one of the unavoidable sources of loss in the air lift.

As a matter of fact, in the air lift the air does not work its way up through a column of fluid of unlimited length and escape out of the fluid at the top, leaving the fluid inert. Before this height is reached, the pipe ends, and there is a continuous discharge of its contents. This discharge of the upper portion of mingled fluid and air at once reduces the weight of the column, and then it begins to be pushed upward by the heavier solid fluid which is now able to force its way in at the lower end. The escape or discharge at the top makes the column continually lighter than is required to balance and entirely resist the inpressing fluid below, so that the solid fluid continues to flow in; then the entire column is kept rising and flowing off at the top, as long as the supply of compressed air is sufficient to maintain this condition of unbalanced pressure.

Pierce and Lewis[1] in their paper presented at the Ft. Worth meeting of the petroleum Division of the A.I.M.M.E. state these principles as follows:

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[1] Pierce, H. R., and J. O. Lewis, Principles of the Air-gas Lift as Applied to Oil Production, *Petroleum Development and Technology*, p. 19, 1927.

“The elements of the air lift are shown in Fig. 83. A U-tube is shown, one arm of which represents the submergence, the other the eduction or flow tube. Water flows continuously into one arm, where it reaches a level that counterbalances both the pressure at point of injection in the flow tube and the pressure of the aerated column above the injection point.”

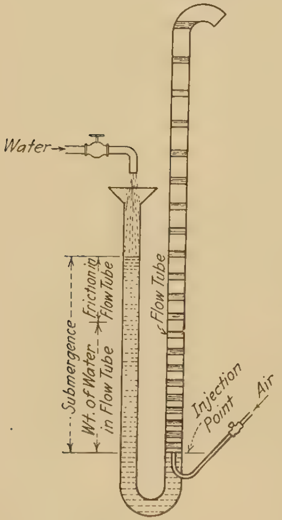

Fig. 83.—The elements of the airlift. (*Pierce and Lewis.*)

“It can be seen at once that the three pressures must be nearly equal at the point of injection, the weight of the water in the flow tube plus the friction being but slightly less than the weight of the water less the slight friction in the submergence tube and also slightly less than the pressure less the friction in the air-feed pipe. The water feeds continuously past the injection point and the air as continuously enters the upward moving column and carries it up and out of the flow pipe under the slightly unbalanced conditions. If the water is fed in more rapidly, more air will be needed to remove it and to maintain the same level in the submergence tube. If the volume of air decreases, the submergence will be increased, which will require a higher air pressure, and if the ingress of water is too rapid, it may overcome the air pressure and volume available and fill up both sides of the U-tube, stopping the flow. If the water flow is decreased, the submergence will be decreased, and the pressure at the injection point will be decreased likewise, but if the rate of water feed is dropped too low, the air will not lift the water and may pass alone up the flow pipe or water may accumulate in the flow and the air pass out through the submergence tube.”

“It will thus be seen that the air lift consists of a balancing and proportioning of parts, pressures and volumes. For a continuous air lift, the necessary elements are a pressure that will feed in the liquid to be lifted against the lift pressure and an equal pressure to feed in the air or other gas, the liquid pressure confining the gas pressure and directing its flow upward. The volume of the gas together with the pressure must equal the foot-pounds of energy to lift the liquid against the frictional resistance together with the waste of energy caused by slippage or drop back of the water in the upflowing column. Thus the air pressure is controlled by the weight and frictional resistance in the flow tube and the volume is controlled by the energy required at the pressure to overcome the weight and friction plus the quantity of air wasted by reason of slippage."

"Figure 83 is diagrammatic and, therefore, the flow is shown as a series of separate slugs of water, whereas in fact a well-designed air lift would show at the bottom of the well a mixture of finely divided bubbles of gas in the water and, near the top, droplets of water in the air. This figure also shows with approximate accuracy the upward expansion of the air and the relative submergence which would be necessary to confine and balance the air injection and flow pressures. The total thickness of the slugs will give the total weight of the column, to which must be added the back pressure resulting from friction."

"It is apparent in that figure that if the pressure is not maintained in the U-tube, air will flow up the U-tube instead of lifting the water. This occurs in an oil well when the rock pressure becomes lower than the lifting pressure, the air or gas backing up into the sand and forcing the oil away from the well instead of lifting it into the well. As a well gets older, this condition is met at some point and it becomes necessary to flow the well intermittently by means of a chamber arranged in some practical manner if the sand is open, though in tight sands the well often will act satisfactorily as a chamber itself. Another and more desirable alternative is to maintain rock pressure by injecting air or gas into the sand in near-by wells."

"Figure 83 shows how the gas expands upstream in the pipe. The relative spaces between the slug of water show not only the expansion but the relative velocity of the flow of gas and water. To keep the velocity constant the cross-section of the pipe must be increased in proportion to the expansion of the gas; this is shown with approximate accuracy, the increase in the cross-section of pipe necessary to maintain a constant velocity in the upflow of the water and the air."

The diagram, Fig. 84, illustrates a well partly filled with fluid and having two pipe lines extending down into the fluid. Assuming that 1 cu. ft. of compressed gas enters a flow line 1,000 ft. below the surface of the fluid, it will be under a pressure of approximately 400 lb. per square inch and will occupy only about one-twenty-seventh (1/27) the space it occupied before compression. For ease of illustration, assume that the cross-section area of the flow line is 1 sq. ft. or, in other words, that each lineal foot of the flow line will contain 1 cu. ft. of either gas or fluid. Then the fluid level will be raised 1 ft. by the mere entrance of 1 cu. ft. of gas. When the gas has in its upward course almost reached the top of the fluid, it will have expanded to a volume of almost 27 cu. ft. and will have thereby raised the fluid level 27 ft. within the flow line.

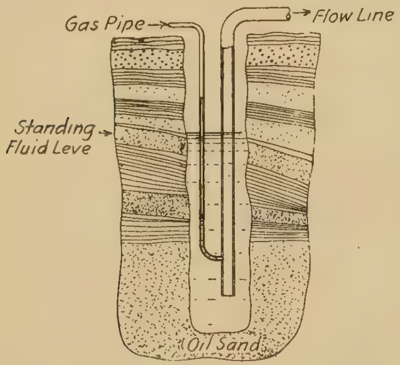

Fig. 84.—Diagram to illustrate the action of the input gas. (*McLaughlin.*)

If no more gas enters from the bottom of the gas pipe, the bubbles of gas will simply burst and the fluid level will fall down 27 ft. to its original level. If more gas is forced in immediately after the first cubic foot has started upward, however, each subsequent cubic foot will behave the same as the one rising above it and each bubble by expanding will still further raise the fluid level in the tubing. The total effect of all these rising gas bubbles will amount, practically, to a stretching of the column of fluid upward and making it a long or high column of mixed gas and fluid having the same weight as the original short column of undiluted fluid. This apparent stretching of the column and raising of the fluid level within the tubing will have no effect upon the fluid at the bottom of the tubing or at any point outside the tubing, because the column inside has not changed in weight.

In a naturally flowing well, the oil is fed into the bottom of the hole by means of the gas pressure and there are sufficient volume and pressure of gas to make a natural gas lift from the bottom of the well to the surface, but when the volume or pressure of the gas becomes insufficient, then it is necessary to add additional quantities of gas or air from the surface.

In order to understand the method of operating and the limitations of the gas lift process it is necessary to give some consideration to matters of theoretical nature which have been investigated in connection with the air lift.

The fluid level cannot continue to rise indefinitely because each bubble must finally reach the surface and escape at atmospheric pressure, having completed its work in its course of rising and expanding. The limiting height of the fluid level will be found when the column is practically filled with a chain of rising gas bubbles.

In actual practice at an oil well, it is unnecessary to insert the extra pipe line for gas. The casing is merely capped and the gas forced into it while the oil flows out through the tubing (Fig. 85) or the gas enters through the tubing and the fluid flow occurs through the annular space between the tubing and casing. This is an adaptation of the Saunders system of the air lift as applied to cased water wells.

The tubing has an opening or several openings at the point where the gas may enter. These openings are far below ordinary fluid level and, as the gas pressure within the casing increases, the fluid level in the casing is forced downward until the holes in the flow line are exposed and the gas enters the tubing. The action is then the same as that in the previous description.

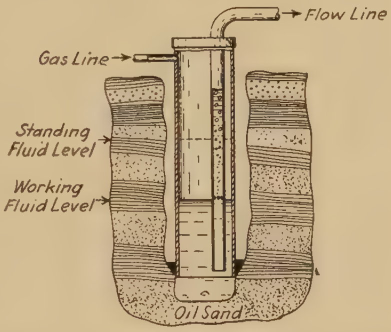

Fig. 85.—Diagram to illustrate the action of the input gas. (*McLaughlin.*)

Aeration, as such, means the intimate mixing of the compressed gas in small bubbles with the liquid being lifted. The lifting effect is due to the buoyancy of these bubbles; that is, the upward pressure or buoyant effect which a liquid exerts on an immersed body is equal to the weight of the liquid displaced or the weight of the amount of liquid equal in volume to the immersed or submerged body. This upward pressure is, of course, counteracted by the weight of the immersed body which, in the case of the compressed air or gas in small bubbles used as the medium of aeration, is negligible.

This buoyant effect is different for water and oil, due to the different densities of the two substances. Water weighs 62.4 lb. per cubic foot while an oil of 35° A.P.I. weighs 52.9 lb. As between water and this particular oil, therefore, the "lifting power" of the compressed gas in oil will be 83 per cent of that of the gas in water, or, the gas would exert about 17 per cent more lifting power in water than in this oil.

It should be noted here, for the purposes of this work, that "lifting power" is ascribed to the gas as a matter of convenience, it being realized that the forces exerted are, in reality, due solely to the relative densities of the liquids involved.

The levitation function of the air being understood, it will be evident that it must be desirable to have it mixed as intimately as possible with all the fluid in the column, so that here ingenuity and invention play an important part in providing means for disseminating the air and mixing it at the start all through the fluid. If such scattering and intimate mixing of the air with the fluid do not occur at the instant of its discharge from the air pipe, no such result can be possible later. It is to be assumed that the air will be distributed through the fluid in bubbles, large or small, and it is better that they should be small, numerous, and, as nearly as possible, at uniform distances apart rather than to have them fewer and larger and irregularly distributed.

It has been shown mathematically[1] that an immersed bubble ascends through an enclosing mass of liquid at a velocity which varies as the square root of the diameter of the bubble. For a bubble of air in water, the relation is $V = 1.385\sqrt{d}$, and for the 35° A.P.I. oil mentioned above, the velocity $V = 1.177\sqrt{d}$, where d equals the diameter of the bubble in inches and V equals the velocity in feet per second. This velocity of the bubble is relative to the containing liquid; it does not matter whether the liquid itself is moving; the bubble moves at the above velocity through the liquid and, as shown by the equation, the velocity increases as the square root of the diameter of the bubble. This constitutes one phase of slippage and shows that, for practical reasons, the lifting gas should be used in as finely divided state as possible. As the bubble expands, due to its reaching regions of lower pressure during the upward flow of the mixture, its velocity, due to the increase of its diameter according to the above equation, will increase relative to the surrounding liquid. This indicates that, if the velocity of the mixture is decreased toward the top of the well by the use of greater flow areas of the containing pipe, the sum total of slippage and the loss due thereto will be reduced. Proportioning the lengths of the various-sized tubing which are used in the flow column in an effort to reduce slippage must be based on the velocities of the mixture obtaining due to the expansion of the gas.

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[1] Daw, A. and Z., "Compressed Air Power," p. 269, Isaac Pitman and Sons.

Summarizing the foregoing ideas, the performance of gas or air in lifting oil from a well tube is a matter, first, of finely dividing the air or gas stream into the smallest bubbles obtainable and then proportioning the uptake pipe to secure such velocity as will prevent excessive slippage of bubbles through oil, and, at the same time, prevent excessive friction from a too high velocity of air-gas mixture in contact with the well piping. All that a footpiece can do toward securing efficiency is to subdivide the air or gas into fine bubbles, but, if the uptake piping is too large or too small, this division into small bubbles is of no avail in securing low cost of plant and low cost of operation.

Then, aside from the continuous feature of the gas-lift system, the other principal reason for the recovery of more fluid is the fact that every foot of solid fluid is displaced from the casing down to where the gas enters the tubing. The gasified column within the tubing can be made to weigh less per square inch of area than the former column of comparatively solid fluid standing in the well during pumping or heading conditions. The term "submergence" does not literally apply to the actual condition in a gas-lift system in the same manner as pictured in water lifts of the past, where a separate tube was used for the introduction of air.

As stated by one authority: "The aim of applying gas lift is twofold, to increase production and to decrease lifting cost. With this well an increase of production was not obtained by gas lift compared with pumping, due to the even inflow of oil from sand into hole. The maximum build-up head of the 24-hr., 6-barrel column of oil in 10-in. 40-lb. casing was 61 ft. of 36 gravity oil or 222 lb. per square inch. This pressure was not sufficient to cause any appreciable lessening of the rate of inflow against time. Should the inflow have been uneven, with an appreciable lessening as the column built up past a certain point, that point would have been a determining factor as to the location of the jets and for the intermittent operation of the gas lift. That, with a very efficient gas-lift installation would have been the basis for increasing production."

Pennington[1] stated:

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[1] PENNINGTON, HARRY, Lift Efficiency Depends upon Skill in Design and Operation, *Oil Weekly*, p. 41, Aug. 19, 1927.

"There are various theories advanced as to the operating principle of the air lift; the original Pohle design, as set out in his patent, and in Fig. 86*a*, discloses the air-piston-water-piston-air-piston principle, or a slug of air and a slug of liquid. While the air lift may be operated in this manner, it has been later proven that intimate mixture of gas and liquid, or air and liquid, shown in Fig. 86*b*, rather than slugging, affords higher efficiencies; due to the finely divided bubbles necessary for intimate mixture, a greater frictional contact area of gas bubble surface is exposed, and since frictional contact of bubble with oil is the means of lifting, the finer the bubbles the greater the efficiency."

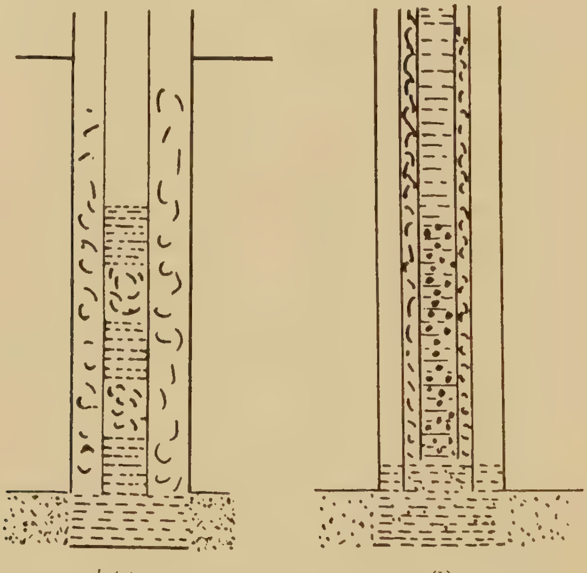
(*a*) (*b*)

FIG. 86.—Action of "slugging" (*a*) and aeration (*b*). (*Pennington.*)

With a finely aerated mixture, the flow of a well is constant without surges of either oil or gas, provided, of course, that the remainder of the problem is correctly solved. To secure this constant flow, not only must the air or gas be finely divided but the quantity of air must be proportioned to the liquid, and, with this total volume of air or gas and liquid, the piping up which the mixture travels must be proportioned so that the bubbles are confined and will not slip through the liquid without doing the maximum work. This means that velocity of oil-gas mixture, up the flow line, must be held as high as possible to prevent slippage, so that relative travel of bubbles and of liquid are as close together as possible; yet, at the same time, the velocity up the flow pipe must not be so high as to set up excessive friction of gas-oil mixture with pipe wall, for friction does not increase as the velocity increases but, approximately, as the square of the velocity. For instance, friction, at a speed of 5 ft. per second is increased sixteen times by increasing the velocity to 20 ft. per second.

It has been stated that, fundamentally, the unbalance existing between a lighter aerated column of liquid and the heavier unaerated column, or, what amounts to the same thing, a column having a comparatively high applied pressure, is the cause of flow in a gas lift. In addition, there is the work done by the expansion of the lifting gas or air as its volume increases, due to moving from a region of higher to one of lower pressure. The expansion of the gas occurs in the pressure of a much greater weight of liquid and, even though there is a certain drop in temperature of the mixture below the probable initial temperature of the oil as it issues from its source horizon which may be accounted for by the work being done by the gas at the cost of its internal energy, for all practical purposes, it is much simpler to consider this expansion to be of an isothermal type rather than of an exponential type approaching the adiabatic expansion of the particular gas in use. This method which results in a much greater convenience will give theoretical results beyond those that could possibly be hoped for in practice.

It is believed that, by measuring the temperature of the oil at the surface and comparing that datum with the preferably measured but otherwise assumed temperature that exists at the producing horizon, some idea as to the type of expansion taking place can be gained. If the surface temperature is high and but slightly less than the formational temperature, the expansion approaches the isothermal—equal temperature—type which is the most efficient. The greater the temperature differential more inefficient the lift and the greater the waste of available energy. Naturally, greater temperature differentials are to be expected with the higher gas factors. If there is an appreciable amount of water present in the production, the end temperature of the expansion will tend to be higher, due to the greater specific heat of water compared to that of oil.

Theoretically, the necessary energy to be supplied to lift a barrel of oil from a given depth can be calculated. The energy content of the gas dissolved and occulated in the oil should be substracted from the total necessary energy, the difference being the energy that must be supplied artificially by means of a compressed agent. But this theoretical consideration is not yet entirely usable because of the lack of definite data as to the energy contained in the oil in the above-mentioned forms. Operators generally know that, in using a gas lift, the rock pressure of the well where it is applied must be greater than the pressure of the gas that is put in; yet, one installation is said to have been made without consideration of this fact with the very obvious result that the gas put in went into the sand instead of lifting oil, as it was intended to do.

Assume a well with both the casing-head and tubing-head valves open. The final fluid level will be such that the pressure due to the fluid column will balance the rock pressure. By introducing high-pressure gas or air into the casing, the fluid level in the annular space is depressed and that in the tubing is raised, but not a corresponding amount or by a corresponding volume of oil moved. The well had originally established a condition of equilibrium in respect to the rock pressure; with the additional applied pressure, the rock pressure has been exceeded and, therefore, some of the liquid in the well opposite the sand will return into the sand pores, especially if the applied pressure is slowly built up; if it is applied quickly, the extremely high resistance of the sand will prevent the immediate entrance of any large amount of the oil that was in the bottom of the well, and the applied pressure, in this case, will show more effect in a higher tubing fluid level. The point here is that an externally applied pressure will cause more or less of the oil that happens to be in the well to return into the reservoir.

When compressed air or gas is first turned on, the fluid in the well being at the same level both inside and outside the flow pipe, the injection of air will cause an initial displacement of the fluid downward below the point of injection of the air, and also upward above it; the relation between these displacements is dependent upon the relative lengths of the fluid column below the point of injection of the air and outside the flow pipe and of that inside the flow pipe above the point where the air enters. As the air bubbles rise in the eduction pipe, they cause a reduction in the mean density of the rising column when the tendency to downward flow below the point where the air enters ceases; the flow is then entirely upward, commencing, generally, with a sudden upward rush of the column. In a well-proportioned air-lift pump, after a few such irregular rushes, the action settles to a more or less steady flow. It is evident, therefore, that the balancing column of fluid must be sufficient to prevent downward flow of the air and its escape through the well outside the eduction pipe.

When considering the pumping of oil by any method, there still exist the problems of conservation of gas and its energy. If a well is pumped in such manner as to produce the lowest quantity of gas compatible with the largest quantity of oil, which means that gas or air is introduced into the well, it necessarily follows that not only will daily production be larger but the total ultimate recovery larger, in something like the proportion of introduced gas to formation gas; that is, when introduced gas is used efficiently together with formation gas for pumping.

The efficient use of formation gas is just as imperative as the use of introduced gas, for the lifting power of both sources of gas is the same per unit of gas, although it serves to increase total recovery percentages to prevent production of formation gas as much as possible in order to hold rock pressures high.

Pennington,[1] on this subject, states:

"As impressed upon the readers of this journal [*The Oil Weekly*] over the past 4 years, formation gas is the propelling agent driving oil through a sand to the well bore, and to the surface when the well is flowing naturally. When the air lift is used for assisting in lifting oil to the surface, then the quantity of gas that is produced with each barrel of oil may be held to a minimum, although at present it is not possible to hold all formation gas within the oil because of solubility—gas in solution comes out with the oil and may be released when pressure is released, either toward the upper end of flow line in the well or in the trap or tank after the oil has been delivered."

"In fields like those of the Seminole area, rock pressure appears to be set up by water from the edges, around the edges in the upper Wilcox sand, with practically no bottom water in the center of the field in the upper Wilcox, but with bottom water in the lower Wilcox. Therefore, the upper sand may be pumped for the time without reference to water encroachment from below, while the lower sand will require more careful operation as to back pressure. However, with or without water, there is no material difference in the result sought; in either case, the main consideration is that of holding formation gas in the formation as long as possible, for formation gas is the sole propelling agent in flush production for driving oil through the sand to the well bore; that is, the pressure of gas maintained on the sand is the most potent factor of flush production."

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[1] PENNINGTON, HARRY, Lift Efficiency Depends upon Skill in Design and Operation, *Oil Weekly*, p. 41, Aug. 19, 1927.

"When rock pressure subsides to approximately the level of the sand, extensive revision of piping will be necessary; at any stage of production, back pressure control is the most important factor, becoming more important as the rock pressure lowers."

"And here it may be said again that air-and-gas lift has its greatest and most permanent field in handling settled production. When cleaning wells, when pulling and replacing rods and tubing, there is risk; when rods or tubing part, there is risk, together with expense. The elimination of all working parts in a well means the elimination of much expense; air lift eliminates these well working parts and since the Mid-Continent is no longer gun-shy of air, the writer believes that its use will be continued in settled fields."

When the standing level of oil in a well has been blown off, and the well is steadily pumping, back pressure carried on the formation is purely incidental. It can be changed by only changing the quantity of air—more air lowering the working level by greater withdrawal of oil and less air elevating the working level, due to lesser withdrawal—or it can be changed by lowering the flow line to secure a greater withdrawal. The point being made is, that when a given quantity of oil is taken constantly from a well, the well, at any stage, will lower its working head to a given level. The method of pumping is immaterial; the quantity of withdrawal controls the working level, and, therefore, the back pressure on the sand.

Compressed air in the air-lift, it has been seen, does not push or jet the column of fluid upward after the lightening of the column has taken place; the flow upward is caused by the unbalanced weight of the solid fluid or pressure outside and below the pipe. This suggests, at once, the necessity of maintaining a sufficient preponderance of pressure from the inflowing fluid, and this is only secured by the submergence of the pipe or its extension to a sufficient depth below the surface of the fluid. The height of the lift is the principal factor in determining the submergence required, the invariable condition being that the higher the lift the greater must be the actual submergence. The percentage of submergence, spoken of later, is another matter.

Contrary to the foregoing theory are the ideas advanced by Benjamin Andrews[1] in an article which furnished the following quotation:

"When we carefully analyze the action of the air lift in deep oil wells and visualize the respective volumes of air and oil at different points in the column, together with the velocities, it becomes obvious that the resulting lift is due almost entirely to blast effect. In other words, the air under high velocity picks up the globules of oil and wafts them just as particles of sand are blown by a sand blast, or as water is lifted from the sea by the water spout."

"This brings us to a study of the action of a vertical blast of air upon globules of wafted liquid. If we had to depend upon data available, in connection with air lift operation we should be very severely handicapped, as no data on investigations of this kind, even if they have ever been made, are of record. Fortunately much experimentation has been done in determining the requirements as to diameters of risers in jet condensers. We find that a globule of water 1 mm. in diameter will remain stationary in air when the upward velocity of the air is 4.22 m. per second. We find that the greater the diameter of the globule the greater will be the velocity of air required to sustain it. The air velocity required for sustentation will be in proportion to the square root of the diameter of the globule; furthermore, we find that the density of the sustaining medium also affects its ability to hold the globules in suspension, this in proportion of the square root of the density of the medium."

"From this it will be seen that if we should blow a well where the liquid is reduced to a mist with globules approximately 1 mm. in diameter and where an air velocity of 4.22 m., or about 14 ft. a second, is maintained in the pipe, with an air density of 1 atmosphere, there would be no movement of the liquid up or down. It would practically fall through the air as fast as the blast raises it. Now, if we increase the velocity of the blast to 60 ft. per second, which, in my opinion, approximates the economical velocity for deep wells at atmospheric pressure, the liquid would be raised at the rate of about 45 ft. per second. Without doubt it is this effect which is responsible for what success has been attained in the blowing of deep oil wells."

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[1] ANDREWS, BENJAMIN, Mechanics of the Air Lift, *Oil Weekly*, p. 35, Dec. 9, 1927.

"It is obvious that some specific velocity will give the best results for specific conditions and it is reasonable to assume that for best performance a well should be piped in reference to velocity and density of operating medium."

"Of course, no air lift is operative unless the back pressure at the entrance of the eduction pipe is less than the incoming pressure of the liquid being pumped. In lifts where the eduction pipe is small, the submergence great, and both the volume of liquid and operating medium unlimited, the back pressure automatically adjusts itself to the pressure of the incoming liquid. Where the eduction pipe is large and the submergence small, the back pressure in the eduction pipe fluctuates within wide ranges; the column overloads, the air backs up in the air pipe and an erratic, violent, and spasmodic surging in the well takes place; and only at periodic intervals is the installation operative. Only that oil is ejected which happens to be in the top of the column where the pressure is reduced, the air expanded, and the velocity in consequence increased, until it is able to break up the oil body into a mist and carry it out by means of the blast effect. In other words, the air and oil in the lower eduction tube surge up and down violently with small lifting effect; finally, air in sufficient quantity slips up through the oil where it is expanded to a volume sufficiently large to meet the proportions required to secure a workable air blast condition."

"The solution of our problem is to maintain everywhere in the eduction column such velocity as experimentation demonstrates to be the most effective."

"To do this we must select the proper diameters of eduction pipe for the different horizons and we must also have under control at all times not only the quantity of air but also the amount of oil that is allowed to enter the mixture. It is this last regulation, that of the oil intake, on which depends the successful and economical operation of the deep oil well lift."

"By providing in the intake of the eduction tube and below the air orifice a pressure regulating value which will curtail or stop the inflow of oil into the pump whenever the pressure in the eduction pipe reaches a desired head a means is provided for knowing quite accurately the pressure and velocity of the mixture of the air and oil at every point in the eduction column, it being understood that a regulated supply of operating medium is fed into the device through an orifice at the bottom, constricted enough to insure a constant supply of air into the pump."

"With these conditions the mathematics of the method develops peculiar and rather astounding phenomena. In the first place, nothing is gained by excessive pressure, for, regardless of pressure, it is not possible to attain velocities higher than certain critical velocities for each specific pipe diameter and depth condition."

"It appears that the proper proportions for maximum efficacy require a discharged velocity of between 60 and 100 ft. per second; a velocity just above the jet of between 40 and 60 ft. per second; and a pressure at the bottom of the eduction column of between 60 and 80 lb. for atmospheric pressure. With these conditions prevailing, from a well 5,000 ft. deep, affording not less than 150 ft. submergence, 700 bbl. of light oil can be pumped per day with 500 ft. of air per minute under a pressure not exceeding 100 lb. at the head of the well. Such a performance contemplates ideal conditions. In actual practice these figures will be distorted in accordance with variation in viscosities and densities of the oils, as well as the densities of the pumping medium; whether the well is operated by air or gas and also whether the well makes sand, or whether the oil itself contains gas in solution to be liberated as the pressure is relieved."

"Where considerable natural gas is made along with the oil the method may be applied taking advantage of the gas pressure. When sufficient gas is present the wells can be made to flow by means of their own natural gas pressure without artificial assistance. If recent statistics are correct, enough gas accompanies all production to provide sufficient means for flowing by this method the total oil content of the respective pools."

Theory in Particular.[1]—The work done by an air lift is derived from the energy which is supplied to the fluid column by the compressed air or gas. The energy is made available to do work by the gas or air being allowed to expand from a higher to a lower pressure. The work done by air in expanding from a high pressure to a lower pressure is assumed here to follow the equation of a perfect gas.

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[1] See PEELE, "Compressed Air Powers" and articles in *Oil Gas Jour.*, by S. F. SHAW.

Let

W = the work done by the air in expanding from one pressure to a lower pressure.
P_1 = the absolute pressure of the air in pounds per square inch at the entrance to the flow pipe (input pressure).
P_2 = the absolute pressure in pounds per square inch at the discharge. (At sea level it is taken at 14.7 lb. per square inch.)
V_1 = the volume of 1 cu. ft. of free air at sea level when compressed to pressure P_1.
V_2 = the volume of 1 cu. ft. of free air at sea level, or at condition (2).
L = the lift in feet to which the fluid is to be raised.
S = the submergence of the entrance to the flow pipe, corresponding to P_1.

Owing to the comparatively large weight of fluid to be raised, the expansion of the air may be considered as isothermal.

The general formula for the work done by the air in expanding is

$$W = P(V_2 - V_1) = PdV.$$

Between the limits of V_1 and V_2 this formula becomes

$$W = \int_{V_1}^{V_2} PdV, \text{ but } P_1V_1 = PV, \text{ or } P = \frac{P_1V_1}{V}.$$

Therefore,

$$W = \int_{V_1}^{V_2} \frac{P_1V_1}{V} dV = P_1V_1 \int_{V_1}^{V_2} \frac{dV}{V}.$$

Integrating, and substituting the limits,

$$W = P_1V_1[\log_e V]_{V_1}^{V_2}$$

$$\frac{V_2}{V_1} = P_1V_1(\log_e V_2 - \log_e V_1).$$

$$V_1 = P_1V_1 \log_e \frac{V_2}{V_1}.$$

Since $P_1V_1 = P_2V_2$ and

$\frac{V_2}{V_1} = \frac{P_1}{P_2}$, the above equation becomes

$$W = P_1V_1 \log_e \frac{V_2}{V_1} = P_2V_2 \log_e \frac{P_1}{P_2}.$$

The work in foot-pounds performed by 1 cu. ft. of air at pressure of P_1 in expanding from volume V_1 to V_2, since V_2 is taken as 1, is, therefore,

$$W = \left[144 P_2 \log_e \frac{P_1}{P_2}\right] \qquad (1)$$

The graphical representation of this equation is shown by Fig. 87.

Theoretically, this same equation will apply to any gas used, since the value of s is 1 for all isothermal work. In reality, in working with natural gas, the value of s for isothermal expansion or compression is slightly below 1, due to the gas deviation from Boyles' law. One gas worked with has a value of s equal to 0.961 for isothermal work.

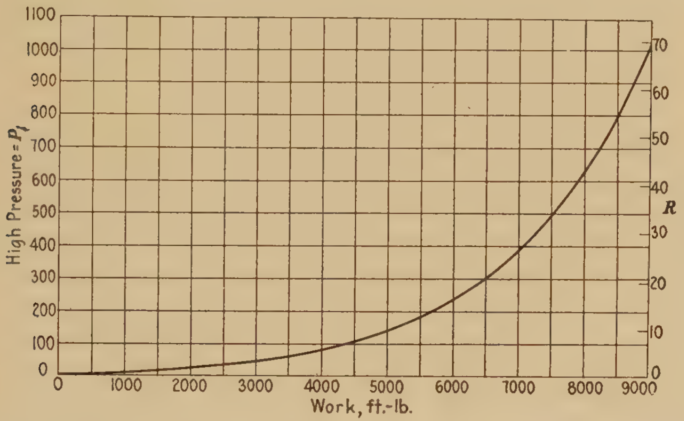

FIG. 87.—Work performed in ft-lb. at 100 per cent efficiency by isothermal expansion of 1 lb. of perfect gas. From P_1 to P_2. $P_2 = 14.7\#/\text{in}^2$. $R = P_1/P_2$.

As considered previously under the discussion of the thermodynamic phases of this application, it is believed that the gas in expanding during the lifting of the oil may start its work isothermally but as the top is approached the type of expansion changes towards the adiabatic. The mean type of expansion would then be according to a value of $s = 1.2$ rather than 1 or 1.29, the latter being considered as the value for adiabatic expansion of an average natural gas.

The equation of work according to an exponential law is

$$W = \frac{P_2 V_2}{s-1}\left[\left(\frac{P_1}{P_2}\right)^{\frac{s-1}{s}} - 1\right]$$

Considering that $V_2 = 1$ and $s = 1.2$.

$$W = \frac{144P_2}{0.2}\left[\left(\frac{P_1}{P_2}\right)^{0.167} - 1\right]$$

$$W = 720P_2\left[\left(\frac{P_1}{P_2}\right)^{0.167} - 1\right] \tag{2}$$

To compare Equation 1, isothermal expansion of air, and Equation 2, mean exponential expansion of gas, and considering only 100 per cent efficiency, let

$P_1 = 314.7$ and $P_2 = 14.7$. Then
$W_1 = 144 \times 14.7 \times \log_e 21.4$.
$W_1 = 1{,}549 \times 3.063 = 4{,}745$ ft.-lb. of work per cubic foot of air at the surface.
$W_2 = 720 \times 14.7[(21.4)^{0.167} - 1]$
$= 10{,}584 \times (1.630 - 1) = 6{,}668$ ft.-lb. of work per cubic foot of gas at the surface.

If the consideration of this subject were to be stopped at this point, it would appear that natural gas, expanded exponentially, would do considerably more work than air expanded isothermally. But these figures are modified by the facts that the 1 cu. ft. of air at the surface resulted from the expansion of 0.0475 cu. ft. of *compressed air* introduced at the bottom of the flow pipe, and the 1 cu. ft. of gas at the surface resulted from the introduction of 0.077 cu. ft. of *compressed gas* at the bottom of the flow pipe. Therefore, 1 cu. ft. of compressed air introduced at the bottom would have done 4,745 ÷ 0.048 = 99,894 ft.-lb. of work while 1 cu. ft. of compressed gas introduced at the bottom would have done 6,668 ÷ 0.077 = 86,597 ft.-lb. of work. This state of affairs is in accordance with practical and theoretical compression practice where it is known that more work is required to compress air than is required to compress gas. And, commercially, air in expanding will do more work than gas expanding through the same range.

Following Shaw's[1] published methods of handling this problem, that is, referring to the work of lifting water and then modifying the results according to the specific gravity of the oil because oil, ordinarily being lighter than water, will require less work to lift:

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[1] Shaw, S. F., Principles of the Air-gas Lift, *Oil Gas Jour.*, p. 40, June 16, 1927.

The work performed in raising 1 gal. of water to a height of 1 ft. is 8.35 ft.-lb. and the work done in raising 1 gal. of water L feet is $8.35 \times L$ ft.-lb.

If Q equals the number of cubic feet of air required to raise 1 gal. of water L feet, there results from Equation 1 for *sea level* conditions

$$Q = \frac{8.35 \times L}{144P_2 \log_e \left(\frac{P_1}{P_2}\right)} = \frac{L}{254 \log_e \left(\frac{P_1}{P_2}\right)},$$

or, changing to the unit of the barrel and introducing the factor of the specific gravity of the oil G,

$$Q_b = \frac{42GL}{254 \log_e \left(\frac{P_1}{P_2}\right)} = \frac{GL}{6.05 \log_e \left(\frac{P_1}{P_2}\right)}.$$

Figure 88 gives the value of $\log_e$ for various values of ratio (P_1/P_2), commonly called the "ratio of expansion." For accurate work the use of tables of the hyperbolic logarithms is advised.

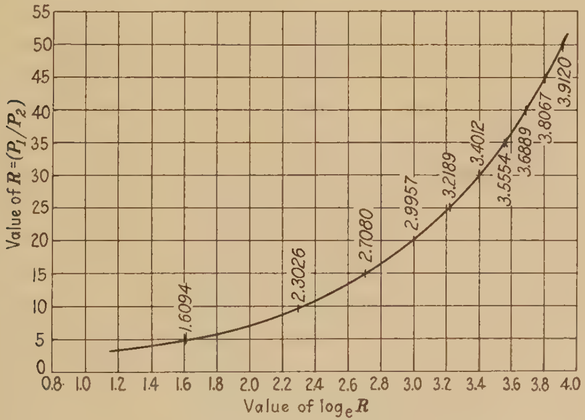

FIG. 88.—Values of $\log_e R$.

The above formula will give the theoretical amount of air required to raise 1 bbl. of oil to a given height, disregarding all losses for friction, slippage, etc.

The following table, after Shaw, is based on the above equation and gives the number of cubic feet of free air, at sea-level basis, required to raise 1 gal. of water to a given height with a given

TABLE XXIV.—CUBIC FEET OF FREE AIR, SEA LEVEL BASIS, AT GIVEN PRESSURE, THEORETICALLY REQUIRED TO RAISE 1 GAL. OF WATER TO A GIVEN HEIGHT IN FEET

	Pounds pressure at bottom																
Lift, feet	50	100	150	200	250	300	350	400	450	500	550	600	650	700	750	800	850
100	0.27	0.19	0.16	0.147	0.136	0.129	0.123	0.118	0.114	0.111	0.108	0.105	0.103	0.101	0.100	0.098	0.097
200	0.53	0.38	0.33	0.293	0.272	0.257	0.245	0.236	0.228	0.221	0.216	0.211	0.207	0.203	0.199	0.196	0.193
300	0.80	0.58	0.49	0.440	0.409	0.386	0.368	0.354	0.342	0.332	0.324	0.316	0.310	0.304	0.299	0.294	0.290
400	1.07	0.77	0.65	0.586	0.545	0.514	0.490	0.472	0.456	0.443	0.432	0.422	0.413	0.405	0.399	0.392	0.387
500	1.33	0.96	0.82	0.737	0.681	0.643	0.613	0.589	0.570	0.554	0.540	0.527	0.516	0.507	0.498	0.490	0.483
600	1.60	1.15	0.98	0.879	0.817	0.771	0.736	0.707	0.684	0.664	0.647	0.633	0.620	0.608	0.598	0.588	0.580
700	1.87	1.34	1.14	1.026	0.955	0.900	0.858	0.825	0.798	0.775	0.755	0.738	0.723	0.710	0.697	0.686	0.676
800	2.13	1.53	1.30	1.172	1.090	1.028	0.981	0.943	0.912	0.886	0.863	0.844	0.826	0.811	0.797	0.784	0.773
900	2.39	1.73	1.47	1.319	1.226	1.157	1.103	1.061	1.026	0.996	0.971	0.949	0.930	0.912	0.897	0.883	0.870
1,000	2.86	1.92	1.63	1.466	1.362	1.285	1.226	1.179	1.140	1.107	1.079	1.055	1.033	1.014	0.996	0.981	0.966
1,100	2.93	2.11	1.792	1.612	1.498	1.414	1.349	1.297	1.254	1.218	1.187	1.160	1.136	1.115	1.096	1.079	1.063
1,200	3.19	2.30	1.955	1.759	1.634	1.542	1.471	1.415	1.368	1.329	1.295	1.266	1.239	1.216	1.196	1.177	1.160
1,300	3.46	2.50	2.118	1.905	1.770	1.671	1.594	1.533	1.482	1.439	1.403	1.371	1.343	1.318	1.295	1.275	1.256
1,400	3.72	2.69	2.281	2.052	1.907	1.799	1.716	1.650	1.596	1.550	1.510	1.476	1.446	1.419	1.395	1.373	1.353
1,500	3.99	2.88	2.444	2.198	2.043	1.928	1.839	1.768	1.710	1.661	1.619	1.582	1.549	1.520	1.494	1.471	1.449
1,600	4.20	3.07	2.607	2.345	2.179	2.056	1.962	1.886	1.824	1.772	1.727	1.687	1.653	1.622	1.594	1.569	1.546
1,700	4.52	3.26	2.770	2.491	2.315	2.185	2.084	2.004	1.938	1.882	1.834	1.793	1.756	1.723	1.694	1.667	1.643
1,800	4.79	3.46	2.933	2.638	2.451	2.313	2.207	2.122	2.052	1.993	1.942	1.898	1.859	1.324	1.793	1.765	1.739
1,900	5.05	3.65	3.096	2.784	2.588	2.442	2.329	2.240	2.166	2.104	2.050	2.004	1.963	1.926	1.893	1.863	1.836
2,000	5.32	3.84	3.259	2.931	2.724	2.570	2.452	2.358	2.280	2.214	2.158	2.109	2.066	2.027	1.993	1.961	1.933

2,100	5.59	4.03	3.422	3.078	2.860	2.699	2.575	2.476	2.394	2.325	2.266	2.215	2.169	2.129	2.092	2.059	2.029
2,200	5.85	4.22	3.585	3.224	2.996	2.827	2.697	2.594	2.508	2.436	2.374	2.320	2.272	2.230	2.192	2.157	2.126
2,300	6.12	4.42	3.748	3.371	3.132	2.956	2.820	2.711	2.622	2.547	2.482	2.426	2.376	2.331	2.291	2.255	2.222
2,400	6.38	4.61	3.91	3.518	3.269	3.084	2.942	2.830	2.736	2.657	2.590	2.532	2.479	2.433	2.390	2.354	2.318
2,500	6.65	4.80	4.08	3.665	3.405	3.212	3.065	2.947	2.850	2.768	2.698	2.638	2.583	2.535	2.490	2.453	2.415
2,600	6.92	4.99	4.24	3.812	3.541	3.341	3.188	3.065	2.964	2.878	2.805	2.743	2.686	2.636	2.590	2.551	2.512
2,700	7.18	5.18	4.40	3.958	3.677	3.469	3.310	3.183	3.078	2.989	2.913	2.849	2.789	2.738	2.689	2.649	2.606
2,800	7.45	5.38	4.56	4.105	3.814	3.598	3.433	3.301	3.192	3.100	3.021	2.954	2.892	2.839	2.789	2.747	2.705
2,900	7.71	5.57	4.73	4.251	3.950	3.726	3.555	3.419	3.306	3.210	3.129	3.060	2.996	2.941	2.880	2.845	2.801
3,000	7.98	5.76	4.89	4.398	4.086	3.855	3.678	3.537	3.420	3.321	3.237	3.165	3.099	3.042	2.988	2.943	2.898
3,100	8.25	5.95	5.05	4.545	4.222	3.983	3.801	3.655	3.534	3.432	3.345	3.271	3.202	3.143	3.088	3.041	2.995
3,200	8.51	6.14	5.22	4.691	4.358	4.112	3.923	3.773	3.648	3.543	3.453	3.376	3.306	3.245	3.187	3.139	3.091
3,300	8.78	6.34	5.38	4.838	4.495	4.240	4.046	3.891	3.762	3.653	3.561	3.482	3.409	3.346	3.287	3.237	3.188
3,400	9.04	6.53	5.54	4.984	4.631	4.369	4.168	4.009	3.876	3.764	3.669	3.587	3.512	3.448	3.386	3.335	3.284
3,500	9.31	6.72	5.71	5.131	4.767	4.497	4.291	4.126	3.990	3.875	3.777	3.693	3.616	3.549	3.486	3.434	3.381
3,600	9.58	6.91	5.87	5.278	4.903	4.626	4.414	4.244	4.104	3.985	3.884	3.798	3.719	3.650	3.586	3.532	3.478
3,700	9.84	7.10	6.03	5.424	5.039	4.754	4.536	4.362	4.218	4.096	3.992	3.904	3.322	3.752	3.685	3.630	3.574
3,800	10.11	7.30	6.19	5.671	5.176	4.883	4.659	4.480	4.332	4.207	4.100	4.009	3.925	3.853	3.785	3.728	3.671
3,900	10.37	7.49	6.36	5.717	5.312	5.011	4.781	4.598	4.446	4.317	4.208	4.115	4.029	3.955	3.884	3.326	3.767
4,000	10.64	7.68	6.52	5.864	5.448	5.140	4.904	4.716	4.560	4.428	4.316	4.220	4.132	4.056	3.984	3.924	3.864
4,100	10.91	7.87	6.68	6.011	5.584	5.268	5.027	4.834	4.674	4.539	4.424	4.326	4.235	4.157	4.084	4.022	3.961
4,200	11.17	8.06	6.85	6.158	5.720	5.397	5.149	4.952	4.788	4.649	4.532	4.431	4.339	4.259	4.183	4.120	4.057
4,300	11.44	8.26	7.01	6.304	5.856	5.525	5.272	5.070	4.902	4.760	4.640	4.537	4.442	4.360	4.283	4.214	4.154
4,400	11.70	8.45	7.17	6.450	5.993	5.654	5.394	5.188	5.016	4.871	4.748	4.642	4.545	4.462	4.382	4.316	4.250
4,500	11.97	8.64	7.34	6.597	6.129	5.782	5.517	5.306	5.130	4.982	4.856	4.748	4.649	4.563	4.482	4.415	4.347
4,600	12.24	8.83	7.50	6.744	6.265	5.911	5.640	5.423	5.244	5.092	4.963	4.853	4.752	4.664	4.582	4.513	4.444

submergence or pressure at the entrance to the flow pipe. From this table the efficiency of an operating air lift can be computed. The factors stated above can be used to convert to terms of air required to lift 1 bbl. of oil and its efficiency determined.

It should be noted that, at altitudes above sea level, a considerably greater quantity of air or gas is required than that which would, theoretically, be necessary at sea level. This must be taken into account when making estimates of compressor capacity required for handling gas lift work in these higher altitudes.

Shaw handles this subject as follows:

The table giving the quantity of air required at sea level or 14.7 lb. per square inch to lift 1 gal. of water applies only to operations at sea level. When the discharge is at a lower pressure, such as would be the case at higher altitudes, a correction must be made for the quantity of air required to lift 1 gal. of water to a given height. Table XXV has been prepared to indicate the percentage of increase required.

TABLE XXV.—PERCENTAGE INCREASE OF AIR REQUIRED TO LIFT 1 GAL. OF WATER 1,000 FT. IN ADDITION TO THE QUANTITY GIVEN IN TABLE XXIV

Altitude, feet	Pounds				
	100	200	300	400	500
	Percentage				
1,000	2.1	2.6	2.8	2.8	2.9
2,000	4.4	5.4	5.6	5.7	5.8
3,000	6.8	8.0	8.4	8.6	8.8
4,000	9.3	10.3	11.4	11.7	11.2
5,000	11.8	13.8	14.5	15.0	15.3
6,000	14.3	16.8	17.4	18.0	18.7
7,000	17.0	19.7	20.6	21.3	21.9
8,000	19.8	22.9	24.0	25.0	25.5

The more general formula for any conditions of altitude, rather than sea level conditions alone, is

$$Q = \frac{2.43G.L.}{P_2 \log_e \left(\frac{P_1}{P_2}\right)},$$

where P_2 is the final absolute pressure, be it atmospheric or some higher, back pressure to which the expansion takes place.

Modifying Equation 2 to the same basis for gas as Equation 1 is for air

$$Q = \frac{8.35 \times L}{720P_2\left[\left(\frac{P_1}{P_2}\right)^{0.167} - 1\right]},$$

and changing to terms of barrels of oil,

$$Q = \frac{G \times L}{2.05P_2\left[\left(\frac{P_1}{P_2}\right)^{0.167} - 1\right]}.$$

Here, of course, Q represents the cubic feet of gas the expansion of which will raise 1 barrel of oil of specific gravity G through the height of L feet.

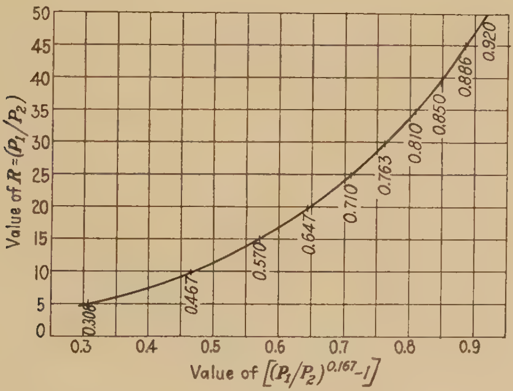

FIG. 89.—Values of $(R^{0.167} - 1)$.

Figure 89 gives approximate values of the expression $[(P_1/P_2)^{0.167} - 1]$. These should be computed for accurate work.

As brought out in Daw's "Compressed Air Power," the mixing of compressed gas or air with the oil in the flow line forms a mixture the density of which is less than the density existing in the column of oil. The density of the mixture will equal the combined weight of the oil and compressed air or gas divided by their combined volumes. The weight of the compressed agent is so small compared to the weight of the oil that the former item can be neglected without practical error and the mean density then expressed by the formula

$$d = \frac{62.4GV}{V + v}$$

where

d = density in pounds per cubic foot.
G = specific gravity of the oil.
V = volume of oil in cubic feet (= 5.6 × barrels).
v = volume of gas in cubic feet.

The volume of gas present varies, of course, with the pressure obtaining; therefore, d itself varies inversely as the existing pressure. To find the mean density existing throughout the length of the column, the various densities can be calculated and averaged, or the figure found directly by the calculus.

Some of the potential energy of the column of oil, or its equivalent pressure supplied artificially, is utilized in overcoming the entrance and other frictional losses, in creating a velocity of flow, etc. Not all of the potential energy, therefore, as represented by the weight of the heavier column of oil is available to balance a lighter and longer column of the aerated mixture and supply the kinetic energy represented by its mass times the square of its velocity.

Considered alone, the smaller the factor, lift divided by submergence, the smaller will be the volume of compressed air or gas required to raise the oil. Such is generally but erroneously stated to be the factor governing efficiency in the design of the lift. It is, however, largely modified by:

1. The frictional resistance, and the head to maintain velocity of flow. The frictional resistance increases directly with the length of the main and is thus directly and adversely affected by the depth of submergence.

2. Losses due to slippage increase directly with depth of submergence; again, submergence adversely affects the efficiency of the lift.

3. The initial pressure P_1 is dependent on the depth of submergence and increases directly therewith; the factors $\log_e (P_1/P_2)$ of Equation 1 and $[(P_1/P_2)^{0.167} - 1]$ increase with depth of submergence and, likewise, with the volume of free air or gas required.

4. The velocity of flow has very great influence on the efficiency of the system as

a. The frictional resistance, other conditions being equal, increases as the square of the velocity.

b. The head to maintain the velocity of flow increases as the square of the velocity, other conditions being equal, but this factor is relatively of small influence on the volume of free air or gas.

c. The slippage losses are affected by the velocity of flow, increasing for the lower velocities and decreasing as the velocity increases.

5. The output from a well increases with increase of velocity of flow; the efficiency, however, falls rapidly after a definite velocity, to be determined for each condition, has been reached.

6. In the end, consideration must be given to the cost of the installation as well as to the power efficiency of the output from the well.

Action of Expansion and Energy Losses during the Cycle.— The effects of the expansion of the air or gas as represented by 100 per cent work were discussed in the preceding section, Theory in Particular. Some of the phases of the application which make the returned work much less than the input work will now be discussed.

It seems probable that the actual character of the expansion is neither isothermal nor adiabatic, but some intermediate value nearer the former than the latter. As the gas and oil rise through the well to the surface, they undergo a gradual loss in temperature, due to variation in the ground temperature at different depths. There is ready opportunity for heat transfer between the warm ascending oil and gas in the eduction tube and the relatively cold descending stream of compressed gas in the surrounding casing.

The descending gas is expanding and, therefore, suffering a loss in temperature. Probably the most important temperature loss, however, is that due to expansion of the gas within the ascending stream of oil. The fluids flow rapidly through the eduction tube; but a few minutes elapse between the time when the gas is injected into the oil at the foot of the flow tube under high pressure until it is discharged at the surface under atmospheric pressure; hence, there is rapid expansion with correspondingly rapid absorption of heat from the surrounding oil. The effect of these various temperature reductions is a definite energy loss which seems inescapable. The actual magnitude of the loss would vary in each individual case, depending upon ground temperature conditions, the rate of flow of the fluids and the specific heats of the oil, the metal casing and tubing, and the surrounding rock masses.

It is believed that only a small cooling action will take place due to the expansion through the nozzles of the footpiece, because the pressure range of the expansion at this point will be small. There must, of necessity, be some pressure difference between the compressed agent and the fluid, else no flow will take place; but this expansion when compared to the range of expansion or pressure drop from the point of the agent's entrance to the well mouth will be very small. It has been stated that, due to the comparatively small pressure difference through the nozzle holes of the footpiece, no trouble need be anticipated from lowered temperatures at this point, such as wax deposition. But it has been found in practice that wax is deposited, and to such an extent, in some cases, as would seriously interfere with the designed purpose of a footpiece. It would, therefore, seem logical, for this reason alone, to employ a footpiece, if one is deemed necessary or advisable, of the simplest possible design and construction; one free from all passages or pockets where wax deposition could take place and, especially, with holes or nozzles so designed that any possible low-temperature effect will occur away from the footpiece itself. For instance, by making the nozzles taper in the direction of flow, the velocity created should carry and mix the lower temperature gas or air with the oil that is flowing past and up the flow pipe, thus preventing wax deposition on the footpiece itself.

While on the subject of cooling effects, it might here be mentioned that, as the agent expands on its upward journey, the energy necessary to cause this expansion, or, in other words, to supply the lifting energy, will be abstracted from the surrounding fluid in the form of heat (adiabatic expansion); there would, consequently, result a fall in fluid temperature as the surface is approached. Use of gas-lift tends to increase paraffin accumulation on account of chilling effect caused by expansion of gas in the well. For instance, in the Texas Panhandle field, the average crude produced congeals at about 62° F. Tests determined that the average temperature of the pay horizon is from 83 to 90° F. There is but little margin, therefore, in which to work in the effort to prevent cooling of the oil to the congealing point and, also, to keep paraffin accumulation at a minimum.

The following notes on the practice in the Panhandle field are extracted from an article by A. F. Hinton:[1]

"Application of heat at bottom of well was the first method tried in the fight against paraffin, and was found successful in keeping the paraffin in solution in the oil. However, it brought on other difficulties. It caused the oil to deposit some sort of bottom settlings on the tubing, and this deposit accumulated rapidly, forming a hard, scaly substance that was hard to get off and gradually clogged up the well. This deposit also accumulated in the bottom of hole, and plastered up walls of the oil pay horizon. However, using the heat treatment, the Marland engineers were able to flow one well 67 days on a gas lift, but its production dropped off steadily on account of this accumulation. Gasoline was used with some success in removing this deposit from the bottom of the hole. However, it was so serious a trouble that the engineers decided that this type heat treatment would not do."

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[1] Hinton, A. F., Gas Lift Helps Solve Panhandle Problems, *Nat. Petroleum News*, p. 27, Feb. 2, 1927.

"Gas to be injected is heated by a specially designed steam heater at each well. This heat is about dissipated at a point some 700 ft. down in the hole, but it is in this section of the well that paraffin accumulation always is the heaviest. The heated gas not only helps the paraffin trouble, but also heats up the crude before it flows from the well."

There are many different possible losses in the cycle of gas-lift operations, some of which can be quantified and some cannot; in fact, the lost energy cannot be accounted for altogether. But certain information is available concerning some of the causes of the energy dissipation that takes place; if due regard is paid to the proper design, the greatest losses can be at least minimized. Some losses are what might be termed of "general" nature and others are "special," or pertaining to some particular phase of the application.

Leakage.—If, due to loose collars, poor joints, holes, or any other possible cause, any of the compressed air or gas is allowed to leak out of the system and thus escape performing its designed work, just that much energy has been uselessly dissipated and has been initially supplied for no useful purpose at all. It would seem fundamental that all apparent leaks should be stopped, but cases have been observed where they were not stopped.

Trapped Air or Gas.—Compressed air or gas, or, for that matter, air or gas which has done its work of flowing oil, can be caught and trapped in high places of a line where it may act more or less as a seal or stopper of any flow of liquid in that line. This is particularly noticeable in comparatively long horizontal or nearly horizontal flow lines which allow time for the gas to come out of solution and collect in the first high spot.

Eddies.—The loss considered here consists of the eddies or turbulence set up by improperly designed flow lines conducting either gas or liquid or a mixture of both. Naturally, this loss is greater in the case of liquid flow than for gas flow. Its suppression is a matter of proper design of the flow lines. As a general rule, the eddy losses usually take place where the direction of flow is changed, where the flow passes obstructions such as collars, and where it passes from one sized line into either a smaller or larger line.

Another form of eddy loss takes place in the rising column of oil and expanding gas; due to the greater velocity of the gas through the oil because of the buoyant effect, some oil flows back and around the bubble, thus creating something of the nature of turbulence within the rising column. This action is usually considered as part of the slippage loss, since no way, outside of velocity consideration, is known of controlling it.

Slippage.—If the compressed agent enters the flow line in comparatively large quantities, sometimes spoken of as "gulps," it remains as a large bubble. This bubble will expand during its ascent to the region of low pressure and, instead of acting as a solid piston and lifting the liquid above it, will allow some of the liquid to drop back through the bubble, this, in effect, constituting by-passing or rather slippage. The larger the bubble the greater the slippage due to the fact that the pipe walls will offer more resistance to the flow of the liquid than to the flow of the air or gas; this will obtain especially in the upper reaches of the pipe, for there the velocity will have increased enormously. This is one of the causes of heading or surging in a flowing well as well as in the case of the lift. If the agent enters the fluid in the form of minute bubbles, it supposedly mixes with the fluid throughout its mass. Then the expansion of these small bubbles with decreasing pressure will tend to carry the mass of the fluid along with them; slippage will be greatly reduced and, consequently, a greater lifting action exerted.

Fluid friction assists the lifting of the oil in the eductor pipe. Pennington[1] described the action as follows:

"An air bubble rises in liquid due to pressure or weight of surrounding liquid on the lighter air or buoyancy, and, due to the lesser specific gravity of air, the bubble rises. Traveling upward, the surface of bubble in contact with liquid sets up friction between air and liquid. Friction being proportional to surfaces in contact, it follows that a unit volume of air in a single bubble sets up a definite friction quantity at definite speed. Hence, to divide the same air bubble into many bubbles means that greater surfaces are exposed for developing frictional contact areas. Take a bubble containing 1 cu. in. of air, at the pressure obtaining, whatever it is. The diameter of this bubble is 1¼ in. and the exposed surface of a truly spherical bubble of this size is 4.90 sq. in."

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[1] Pennington, Harry, Lift Efficiency Depends upon Skill in Design and Operation, *Oil Weekly*, p. 41, Aug. 19, 1927.

"Now, the same bubble may be divided into smaller sizes, and say we have divided it into bubbles ⅛ in. in diameter, each containing 0.00102 cu. in. of air. There will then be 1,000 bubbles each ⅛ in. in diameter. The surface of these 1,000 bubbles is 49 sq. in., or just ten times as much when finely divided, and the same amount of air then does far more work, for frictional work is proportional to the frictional contact areas."

Frictional Losses.—These losses result from the expenditure of the energy necessary to move a fluid, either a liquid or gas, past a bounding surface.

Starting with the compressed agent as it leaves the compressor cylinder, or in case of after cooling, the coolers, there is the loss due to friction in the pipe, fittings, valves, etc., through which the agent must flow from the compressor to the well head and then down to the point of mixing with the fluid. This loss varies with many factors, but mainly the pipe size and gas or air velocity.

Coming now to the so-called "footpiece" or flow device where the compressed agent, minus what energy has been expended in getting it to this point, passes through the holes in a length of perforated pipe or enters a chamber from where it passes out through a series of small-sized nozzles into the fluid; there will be friction and eddy losses in the footpiece unless it is designed on stream-line flow principles and with the nozzles of the proper shape to provide an adiabatic expansion. The nozzles must, of necessity, be small, for the main idea at this point is to force the agent in as finely divided state as possible out into the fluid, securing an intimate mixture. In case that no footpiece is used, the compressed agent being allowed to depress the liquid level and then flow under the edge of the tubing, there will be eddy losses and more or less throttling effect, the losses thus corresponding to what may be classified as wire drawing rather than frictional losses, though there will be some friction loss present.

The losses resulting in the upward movement of mixed liquid and gas will be mainly the frictional losses resulting from the higher velocities of the fluid flow; this increases greatly towards the top of the well with the increase in velocity. The fluid flow will consist of the elements of both liquid and gas flow, the former existing in the lower parts of the well and the latter near the top. At no place will the fluid be liquid or gas only, but the above types of flow will be approached in the regions mentioned. Whatever the type of flow, its effect is to generate a certain amount of heat which tends to increase the temperature of the fluid, but it is hardly believed that this action would be enough entirely to counteract the lowering in temperature due to the expansive action of the gases. The actual losses from this cause can be approximated only but should be taken into account as should the losses caused by fittings and other restrictions to the fluid flow. The matter of losses due to eddies, etc., cannot be quantified but a small percentage allowance based on experience can be made, if so desired.

Working principles and data are available for either type of fluid flow alone, but when it comes to predicting frictional losses for the flow of the mixture of the two, *i.e.*, oil and gas or air, experience and judgment are the only sources of information. A thorough treatment of the whole subject of friction losses[1] during flow can be found in Lucke's "Engineering Thermodynamics."[1] The standard engineering handbooks give detailed treatment of the subjects of gas and liquid flow. One of the best detailed treatments of gas flow for design purposes is found in Litchy's book.[2]

The standard formula for head or pressure expended because of friction in fluid flow is of the general form

$$h = f\left(\frac{4l}{d}\right)\left(\frac{u^2}{2g}\right)$$

where

h = head lost.
f = coefficient of friction from experiment.
l = length of pipe.
d = diameter of pipe.
u = velocity.
g = acceleration due to gravity.

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[1] LUCKE, "Engineering Thermodynamics," p. 1111, 1st ed.

[2] LICHTY on "Natural Gas," pp. 371*ff*., 1924 ed.

This formula takes many special forms for the flow of either oil, gas, or air, depending upon the purpose for which the formula is intended. Oil flow requires consideration of viscosity, temperature, and density. Air or gas flow requires consideration of temperature and density. But the main consideration here is the influence exerted by the different quantities that enter into the problem. Greater frictional losses are sustained with increasing values of the coefficient of friction, length of flow line, as the square of the velocity, and with decreasing flow-pipe diameter.

According to the laws of fluid friction, the resistance for all fluids, whether fluid or gaseous is:

1. Independent of the pressure between the masses in contact.
2. Directly proportional to the area of rubbing surface.
3. Proportional to the square of the relative velocity at moderate and high speeds and to the velocity nearly at low speeds.
4. Independent of the nature of the surfaces of the solid against which the stream may flow but dependent to some extent upon their degree of roughness.
5. Proportional to the density of the fluid and related in some way to its viscosity.

The heaviness of the mixture is decreased at the submerged end of the rising main by compressed air or gas mixing with the oil, and, as it further decreases correspondingly to the varying relative volumes of air or gas and oil caused by the expansion of the compressed agent in its upward flow through the rising main, the velocity of flow increases with the expansion.

But the character of the losses due to friction changes, along with the expansion, from the greater losses due to the movement of a liquid to the order of the smaller losses due to the movement of gas. When a steady flow of the mixture, which is the best operating condition, prevails, and the mixture issues as a foam or froth, it is believed that the losses will be relatively small compared to losses due to liquid friction.

These considerations apply to the flow of all fluids, the main difference appearing in the absolute value of f, the coefficient of friction. No attempt will be made here to give the various formulæ of fluid flow because most engineers have their favorite formula. As for the values of f, for air, gas, or oil, reference should be made to the standard engineering handbooks.

Under the subject of Hydraulics of Oil-well Flow, Fig. 16 showed the frictional losses sustained for various quantities of oil flowing through different sized standard tubing and casings. Figure 90 shows the frictional losses sustained by different quantities of air flowing through different standard sized pipes.

Frictional losses accompanying the flow of gas are comparable to the losses for air flow on the basis of the specific gravities as shown by the data of Fig. 91.

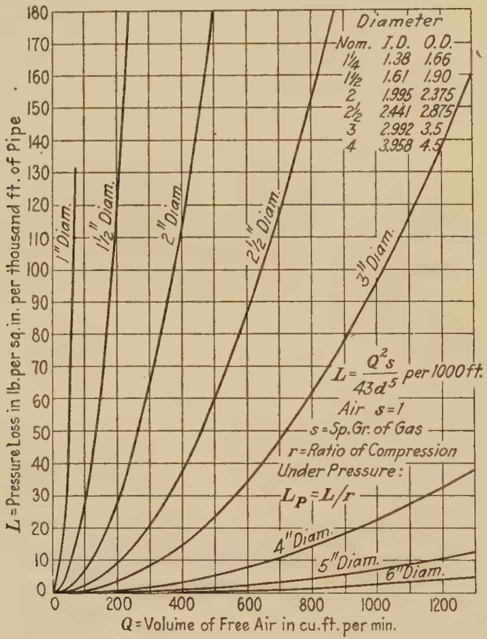

FIG. 90.—Typical pressure losses due to friction in air flow.

The subject of flowing a well, either through the tubing or the annular space, will be considered here only as it pertains to flow areas and the frictional effects. Friction of liquid flow entails greater net energy losses than the friction resulting from gas flow. It would, therefore, appear that, as a general rule, the flow of compressed gas or air should be confined to the smaller of two available channels of flow, to the channel having the greatest "wetted surface"—otherwise known as the area or surface causing friction—and to the channel having such an area of flow that, when compared to the other available channel, the resulting velocity will be highest. The channel having the most favorable conditions for fluid flow would be left for the flow of the mixed oil and gas. The ultimate results will be the least possible frictional losses for the particular system as installed.

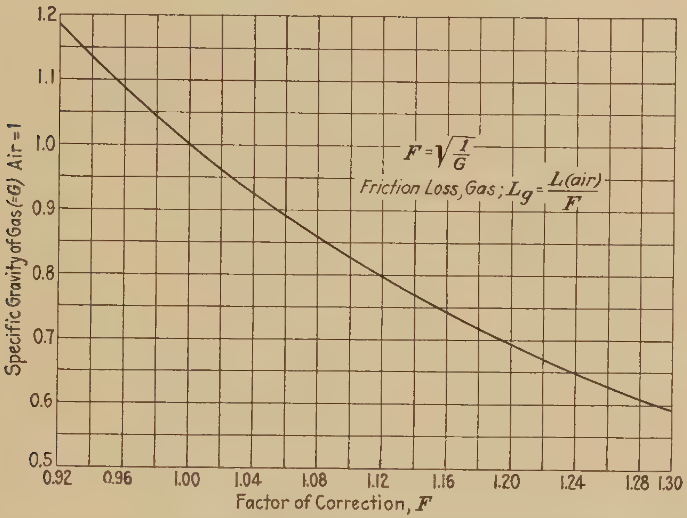

FIG. 91.—Correction factor for friction loss in flow of gas, compared to flow of air. (Basis of sp. gr.)

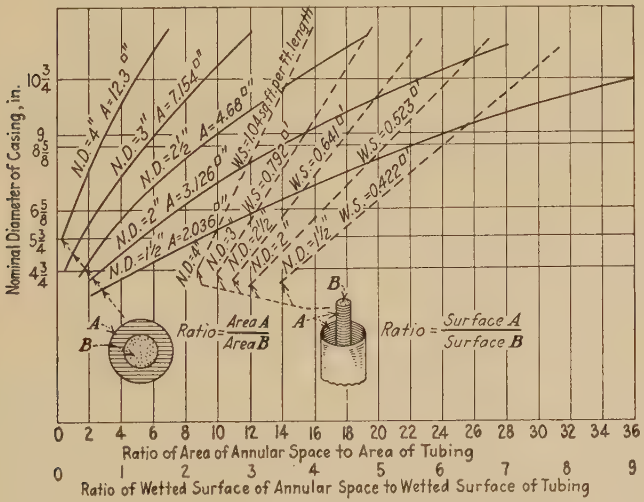

FIG. 92.—Ratios of flow areas and wetted surfaces for different combinations of A.P.I. casing and tubing.

Table XXVI gives the data pertaining to flow areas and wetted surface for certain different combinations of A.P.I. standard casing and tubing. A similar table could easily be made up for

TABLE XXVI

Casing					Tubing																		
Nominal diameter	Inside diameter	Area, square inches	Wetted surface, square feet per foot of, length	Weight per foot	Nominal diameter	1¼			1½			2			2½			3			4		
					O.D./area	1.660/2.165			1.900/2.835			2.375/4.430			2.875/6.492			3.500/9.621			4.500/15.90		
					I.D./area	1.380/1.496			1.610/2.036			1.995/3.126			2.441/4.680			3.018/7.154			3.958/12.30		
					Coupling, O.D./area	2.200/3.801			2.500/4.909			2.870/6.469			3.517/9.715			4.200/13.85			5.216/21.37		
					Weight per foot, pounds	2.4			2.9			4.6			6.4			8.7			12.6		
					Wetted surface per foot length $\left(\frac{\text{O.D.}}{\text{I.D.}}\right)$	0.435/0.362			0.497/0.422			0.623/0.523			0.754/0.641			0.920/0.792			1.18/1.04		
						1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
4¾	4.082	13.08	1.067	16		8.7/2.96	10.44/6.98	1.502/4.14	6.4/2.54	10.26/5.04	1.564/3.70	4.2/2.05	8.65/2.76	1.690/3.23	2.8/1.67	6.59/1.62	1.821/2.84	1.8/1.35	3.46/0.48	1.987/2.51			
5¾	5.090	20.35	1.332	20		13.6/3.68	18.19/12.15	1.767/4.87	10.0/3.16	17.52/8.62	1.829/4.33	6.5/2.55	15.92/5.09	1.955/3.74	4.4/2.08	13.86/2.96	2.086/3.25	2.8/1.69	10.73/1.50	2.252/2.84	1.65/1.28	4.45/0.28	2.512/2.42
6⅝	5.855	26.93	1.531	26		18.0/4.25	24.77/16.56	1.966/5.43	13.2/3.64	24.10/11.10	2.028/4.80	8.6/2.94	22.50/7.20	2.154/4.11	5.8/2.40	20.44/4.37	2.285/3.56	3.8/1.94	17.31/2.42	2.451/3.09	2.2/1.47	11.03/0.90	2.711/2.61
8⅛	7.285	41.68	1.906	35½		27.9/5.27	39.52/26.41	2.347/6.48	20.5/4.52	38.85/19.10	2.403/5.69	13.3/3.65	37.25/11.92	2.529/4.84	8.9/2.98	35.19/7.53	2.660/4.15	5.8/2.41	32.06/4.48	2.826/3.57	3.4/1.84	25.78/2.09	3.086/2.97
8⅝	7.825	48.09	2.048	36		32.2/5.57	46.93/31.9	2.483/6.86	23.6/4.86	45.26/22.2	2.545/6.03	15.4/3.92	43.66/14.00	2.671/5.11	10.3/3.20	41.60/8.93	2.802/4.37	6.7/2.59	38.47/5.37	2.968/3.75	3.9/1.98	32.19/2.61	3.228/3.15
9	8.150	52.17	2.132	40		34.9/5.90	50.01/33.5	2.567/7.09	25.6/5.06	49.34/24.2	2.629/6.23	16.7/4.08	47.74/15.25	2.755/5.27	11.2/3.34	45.68/9.8	2.886/4.50	7.3/2.70	42.55/5.94	3.052/3.85	4.2/2.06	36.27/2.94	3.312/3.18
10¾	9.85	76.20	2.577	51		51.0/7.14	74.04/49.5	3.012/8.31	37.5/6.12	73.37/36.0	3.074/7.28	24.4/4.94	71.77/22.91	3.200/6.12	16.3/4.03	69.71/14.9	3.331/5.19	10.7/3.26	66.58/9.3	3.497/4.41	6.2/2.49	60.30/4.9	3.757/3.61

NOTE:
Column 1. (Ratio of areas of casing and tubing)/(ratio of inside diameters).
Column 2. (Area of annular space, tubing, not collars, in square inches)/(ratio of areas of annular space and tubing).
Column 3. (Total wetted surface of annular space per foot of length in square feet)/(ratio of wetted surface of annular space and tubing).

any casing or tubing types and combinations being used. The data of this table for the ratio of frictional surface of the annular space to that of the tubing and the ratios of flow areas have been shown graphically in Fig. 92.

Submergence or Working Pressure.—The submergence as such is the depth of submersion of the point of outlet of the compressed agent input pipe below the fluid level in a well. Shaw[1] has published a very clear exposition of the subject of submergence from which the following quotation is taken:

"The fluid level in an oil well or water well is that point to which the liquid will rise under existing conditions. If there be no discharge of the liquid from the well, the liquid will assume a static condition. If the liquid is being pumped, whether by plunger pump or air lift, the level of the liquid will be lowered, depending upon the rate at which the liquid will enter the well when the well is being pumped at any given rate."

"The term 'submergence' has been employed for many years by those versed in air lifts to denote the height of the liquid above the point at which the air is admitted at the lower end of the air tubing. When starting a well on the air lift the submergence is usually higher than when the well is being pumped; this is termed 'starting submergence.' When the well has reached a stationary condition it is called 'working submergence.' Submergence may be expressed in feet of water, feet of oil, or in pressure in pounds per square inch. Before calculations for air lifts can be made, it is necessary to determine the lift, that is, the height to which the liquid must be raised, and, in order to do this, it is necessary to ascertain the submergence in feet, since the total vertical length of the air pipe minus the submergence is the lift."

"There are three general types of air-lift installations:

"1. Two pipes, side by side, connected near the lower end, the air flowing through one of the pipes to the connection, and the mixed air and liquid rising through the other pipe.

2. Two pipes, one inserted in the other and the air flowing through the inner pipe to the lower end, the mixture of air and liquid rising in the annular space between the two pipes. This is called the 'central air-lift system.'

3. Two pipes, one inserted in the other, the air passing through the annular space between the two pipes, the mixture of air and liquid rising in the inside pipe. This is called the 'Saunders system.'"

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[1] Shaw, S. F., Principles of the Air-gas Lift, *Oil Gas Jour.*, p. 374, June 16, 1927.

"In the first type, a liquid level is maintained which can be measured. In the second and third types the liquid column is in motion in both pipes and submergence cannot be actually measured, but the level to which the liquid would rise at the instant the air is cut off from the air pipe can be determined by noting the gage pressure at the top of the well and subtracting from this the friction loss due to the air flowing through the air pipe, thus obtaining the pressure at the bottom of the air pipe. The feet of corresponding submergence can then be determined from this figure of pressure, making allowance for the specific gravity of the particular liquid being lifted."

"Oil wells which have ceased to flow present an exact parallel to water wells as regards submergence. One may be somewhat puzzled as to the manner of handling submergence in flowing wells, but a little study in air-lift practice will reveal the fact that the theoretical submergence presents exactly the same problem as is found in a water well; submergence and lift can be calculated from the pressure obtaining at the lower end of the flowing column."

"A water well would show a condition of ebullition if insufficient air were admitted to cause it to flow; the level would be found higher than the level that would obtain if the column were not made lighter by the air passing through it. This does not change the considerations of submergence, however, as the water column is considered as if it had a specific gravity of 1, and not the accidental specific gravity due to variable quantities of air slipping through it. An oil well should be considered in the same manner; that is, the submergence is that which would be measured if there were no gas mixed with it and slipping through it. For a given pressure, the submergence of most oils is greater than that of water, owing to the lower specific gravity of the oil."

This submergence, of course, varies with ratio of height of fluid column to depth of well, and also with diameter of casing and tubing. It varies also with method used in flowing oil from the well, *i.e.*, proper submergence in a well in which oil is flowed out through the tubing is very different from proper submergence where the oil flows through the annular space between the casing and tubing.

On the submergence, or depth that the bottom of the flow pipe is immersed below the working level of the oil in the well, will primarily depend the weight and height of the mixed air or gas and oil which can be supported in the flow pipe. The conception of submergence and lift can be expressed by equations as follows, as adapted from Daw's "Compressed Air Power:"

Let a = area of column in flow pipe in square feet.
y_1 = mean density of aerated column.
y = density of the oil.
D = submerged depth in feet.
L = lift above fluid working level in feet.
$D + L$ = total length of flow pipe in feet.

Then

$$ay_1(D + L) = ayD$$

and

$$y_1 = y\frac{D}{(D + L)}.$$

Let r = the ratio of $D/(D+L)$, which is the ratio of submergence to length of flow pipe, and then

$$y_1 = ry.$$

This states that, theoretically, the density of the mixture in the flow pipe to the density of the oil varies as the ratio of submergence.

Percentage submergence is usually employed; it amounts to $R = 100\frac{D}{(D + L)}$ per cent or $R = 100r$ per cent of the flow pipe.

The submergence D and lift L expressed in terms of r are

$$D = r\frac{L}{(l - r)} \text{ and } L = \frac{D(l - r)}{r}.$$

EXAMPLE: For 60 per cent submergence,

$$R = 60; r = 0.60.$$
$$D = 1.5L; L = 0.67D.$$

The most efficient value of the submergence has not been theoretically determined nor has a rational formula been established. In practice, it has been found that submersion should be from one to three times the lift, the larger values giving greater efficiency, particularly with low lifts. While the percentage submergence decreases with deeper wells, the submersion in feet increases.

The submergence required to support the column of mixture in the flow pipe above the points corresponding to various pressures is simply

$$D = \frac{P_1 - P_0}{0.434G} \text{ ft.}$$

where

P_0 = atmospheric or back pressure.
P_1 = any higher pressure at the depth.

As brought out by Pennington, submergence of the air or gas line is not truly indicated by the gage pressure reading at the surface, for there is friction of air in the piping between gage and bottom of air line, but the working submergence may be

TABLE XXVII.—VARIATION OF SUBMERGENCE WITH GRAVITY OF OIL

Gravity of oil, Beaumé	Specific gravity	Weight per gallon, pounds	Pressure caused by submerging a pipe 100 ft., pounds	Actual horsepower required to lift 1 barrel 100 ft.
15	0.9660	8.048	41.82	1.023
16	0.9595	7.994	41.54	1.015
17	0.9330	7.939	41.20	1.009
18	0.946	7.885	40.96	1.002
19	0.94	7.831	40.70	0.995
20	0.934	7.781	40.44	0.989
21	0.928	7.731	40.18	0.983
22	0.922	7.681	39.92	0.976
23	0.916	7.635	39.66	0.97
24	0.91	7.581	39.40	0.964
25	0.904	7.536	39.14	0.957
26	0.899	7.49	38.92	0.952
27	0.893	7.44	38.66	0.946
28	0.887	7.39	38.40	0.939
29	0.881	7.344	38.14	0.933
30	0.875	7.294	37.88	0.927
31	0.871	7.248	37.70	0.922
32	0.865	7.206	37.46	0.916
33	0.856	7.16	37.17	0.906
34	0.855	7.20	37.03	0.905
35	0.849	7.073	36.87	0.899
36	0.844	7.031	36.54	0.893
37	0.839	6.994	36.32	0.888
38	0.834	6.952	36.11	0.883
39	0.829	6.911	35.89	0.877
40	0.825	6.873	35.62	0.873
41	0.821	6.836	35.54	0.869
42	0.815	6.794	35.28	0.863

NOTE: In using this table, the actual Beaumé reading is used without temperature correction.

obtained by quickly closing the air-line valve when the pressure, as shown on gage, subsides for a few seconds and then rises again. The lowest pressure reading so obtained is the submergence pressure in pounds, and for determining the height of oil that corresponds to pounds pressure, Table XXVII is inserted.

Maximum percentage submergence exists when the well is first placed on air and, as the rock pressure drops and the air line is lowered, the percentage submergence obtainable gradually decreases, setting up lower operating efficiencies successively until the well bottom is reached. But, with the air line on bottom, an efficient installation for quantities of oil as low as 5 bbl. per day is possible, considering the problem as a whole.

All wells pumped with air or gas operate with submergence, for the very principle upon which the air lift is based is submergence. It may seem that there is no submergence in certain types of installation where the compressed agent actually forces the oil level down to the lower end of the tubing, but submergence is here indicated by pressure at the lower end of inner pipe. Without submergence no air lift can operate.

The consensus of opinion of many production engineers is that the term "working submergence" for water lifting with air is inadequate and meaningless when used in petroleum production, since submergence never actually exists in a flowing oil well. The essential factors to be defined are the pressures involved and the rate of flow of fluid into the hole under these pressures. The pressures of importance are the pressure in the formation, commonly called the "rock pressure," the gas working pressure, and the pressure on the pay sand, due to the fluid below the bottom of the tubing plus the working pressure required for the injection of extraneous gas into the well. The differential pressure causing the flow of fluid into the well bore is the difference between the static rock pressure and the summation of the two variable pressures imposed upon the sand. This point has come up as a result of the type of installation used for lifting oil where the compressed agent is sent down through either the tubing or the annular space and the well flowed through the other channel. In water-well work, the compressed air was sent down through a special pipe to the point of inlet to the rising main; an actual physical submergence of the rising main existed with this installation. Any term or designation may be employed when it is understood that the gas working pressure at the point of inlet to the flow pipe is synonymous with the term "submergence" as used above. Possibly the term "working pressure" at the point of inlet may better apply since there is no actual physical submergence. This is one of the points which it is hoped will be cleared up through a standardization of terms employed.

With reference to the well pressures mentioned, it is evident that the pressure due to the column of fluid below the bottom of the tubing is not equivalent to the weight of the column of fluid but to some pressure less than that, the amount of pressure being dependent on the velocity of the moving column and the velocity, in turn, being dependent on the rate of withdrawal.

It has been shown that the greater the submergence the less the volume of the agent required to lift the oil from any given depth. But pressure considerations often dictate otherwise, because, as the submergence increases the required pressure becomes greater. This is an economic consideration and must be solved by well-known means before the proper size compressor can be installed.

Keeping in mind the idea that it is the relative differences in weight or exerted pressures of the columns of fluid on the inside and outside of the flow pipe that causes the lighter column to rise, it is seen that by lowering the agent's outlet into the fluid, that is, increasing the submergence, a greater differential of pressure will be established and a higher column of fluid in the flow pipe will result. The submergence required is that amount which will cause a flow to the height desired. This can be only approximated on paper; the installation itself must be flexible enough to be able to vary the amount of submergence and from experience determine the best working conditions for that particular well.

The submergence obtainable is a very important feature in air-lift considerations. In most instances, when air-lift installations are being considered, only a few operators can supply figures indicating the point at which the fluid level stands and to what point it would be lowered if the pumping rate were increased. It would be advisable to make closed-in pressure readings immediately after a well begins to flow and to keep a record of such readings made at intervals as the flow and the pressure dropped. A study of these readings in relation to the decline would be very interesting and would be of great value in connection with later installations of air lifts.

At this point, it will be well to develop another conception of submergence, originating with H. P. Porter[1] of the Gypsy Oil Company which are extracted here:

"Submergence is the distance that the column of oil rises in the tubing when sufficient pressure has been applied above the oil in the annular space to force its level down to the bottom end of the tubing and *vice versa*, if the well is to be flowed through the annular space, submergence is the distance that the oil level will rise in the annular space when sufficient pressure has been applied to force the oil level in the tubing down to its bottom end."

"This idea then amounts to finding what height or length of the annular space times what flow area it may afford, depending upon the combination of casing and tubing that may be in use, will be equivalent to the flow area of the tubing times the height of the fluid in the tubing; in other words, equate the two volumes and solve the equation for the length or height of the fluid column in the channel through which the flow is to take place."

Let A_a = flow area of the annular space.
A_t = flow area of the tubing.
L_a = the length of the fluid column in the annular space.
L_t = the length of the fluid column in the tubing.

Then

$$L_aA_a = L_tA_t.$$

This states that if the flow area of the annular space is twice the flow area of the tubing, the height of the oil in the annular space must be one-half that in the tubing if the two volumes are the same.

It is a simple matter to compute and tabulate the ratio of flow areas A_a/A_t for the combinations of casing and tubing in use; calling this ratio R,

$$L_a = \frac{L_t}{R} \text{ or } L_t = RL_a.$$

These expressions merely state that, for equal volumes of fluid, the height that it stands in the annular space is $1/R$ part of the height in the tubing or the height in the tubing is R twice the height in the annular space.

Mr. Porter takes into consideration the volume occupied by the collars, but it is believed that while the practice is correct the difference amounts to such a small relative figure that the error entering into the work, by omitting this consideration, is negligible in comparison with other uncertainties that exist.

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[1] PORTER, H. P., Tables for Figuring Tubing Submergence, *Nat. Petroleum News*, p. 67, July 6, 1927.

Taking his example: Assume that there is sufficient pressure available to balance a 1,200-ft. column of liquid. The well is to be flowed through 6⅝-in. casing and the compressed agent enters through 2-in. tubing. A_a (flow area of annular space) equals 27.33 sq. in. A_t (flow area of the tubing) equals 3.14 sq. in.

$$R = \frac{27.33}{3.14} = 8.70.$$

Then, since a column of fluid 1,200 ft. high can be maintained in the annular space, 1,200/8.70 or 138 ft. of this column will be supplied by the volume of the oil in the tubing and the remainder or (1,200 − 138) = 1,062 ft. must be supplied by lowering or immersing the tubing string this amount. In other words, the lower end of the tubing is submerged 1,062 ft. Then, when the tubing is filled with the compressed gas or air, the oil will stand 1,200 ft. in the annular space. If the well head is within this distance of the bottom of the tubing, the well will flow; if the distance between the bottom of the tubing and the well head is more than 1,200 ft. the well will not flow initially. More pressure will be required.

If this well is to be flowed through the tubing, 138 ft. of the oil in the annular space will fill the tubing to a height of 1,200 ft.; therefore, the bottom of the tubing should be submerged 138 ft. The applied pressure in the annular space, in forcing the fluid level to the bottom of the tubing, will fill it and support the 1,200-ft. column.

To show Mr. Porter's method of handling the consideration of the volume of the collars, and using a figure 98.0 instead of 8.14 as the ratio of the flow area of the annular space outside collars to the tubing flow area, he states that there will be about 54 collars, each 4½-in. long, in the 1,200-ft. column. The total length of couplings is about 20 ft. or 1.66 per cent of the length of the possible fluid column and the tubing is 98.33 per cent of this length. For the specified combination of casing and tubing sizes, the ratios are 8.70 for the tubing and 8.06 for the collars.

$$\frac{1200}{8.70} = 138 \text{ (tubing)}.$$

$$\frac{1200}{8.06} = 149 \text{ (collars)}.$$

Then, since 1.66 per cent of the total length consists of collars and 98.33 per cent consists of tubing,

$$(138 \times 0.9833) + (149 \times 0.0166) = 138.2 \text{ ft.}$$

which figure corresponds to the figure of 138 ft. as used above when collars were not considered.

In practice, the matter of submergence assumes the greatest importance, and mistakes or misjudgments in this particular are not infrequent. In planning an air lift for a tubed well wherein the fluid does not rise to the surface but stands constantly at a certain distance below the surface, it is comparatively easy to compute, approximately, the submergence which should be adopted for delivering the fluid at a given height; but if, when the pumping begins, the height of the fluid in the well falls any considerable distance, as it usually does, then the proportionate and the actual submergence may be quite inadequate. The submergence will be reduced as many feet as the surface of the fluid supply falls, and the lift will be increased an equal distance, a double-acting cause of inefficiency. In many cases where a new air lift is installed, provision is made for lengthening or shortening the pipes to get the best submergence which the developed working conditions dictate as necessary but which could not have been anticipated.

With a given submergence, the lift may be greater or less, within wide limits, and the lift will still work but there is, for each case, an approximate ratio of submergence to lift which gives the best results, both as to the volume of liquid raised and, also, as to the air cost, or power cost of raising it. With a fixed submergence, whether the lift be proportionately small or whether it be as high as possible, the air pressure required will be the same, but, while the pressure is thus determined by the submergence, the actual volume of air per unit of time and, also, the volume of fluid raised will be influenced and determined by other conditions, especially by the actual volume of air supplied and the resultant rate of flow of the fluid.

For the air pressure required for any lift and with any percentage of submergence, it is convenient to divide the actual submergence in feet by two to get the gage pressure in pounds. This allows enough pressure in excess of that due to the fluid (water) head to allow for the pipe friction and other losses.

Consider the following empirical formula which sometimes is used to compute the volume of air necessary to operate a water lift:

$$Q = \frac{L}{\text{Log}\,\frac{(D+34)}{34}} \times C$$

where

L = lift in feet.
D = submergence in feet.
C = an experimental constant (234 used here).
Q = volume of free air required.

The most striking thing observable in an examination of this formula is that the volume of free air required per gallon of water lifted, in this case, constantly decreases as the submergence increases. Thus at 25 per cent submergence and 200 ft. lift, the free air required per gallon is 1.83 cu. ft., while for the same lift and 60 per cent submergence the free air is 0.88 cu. ft., or less than one-half. In the first case, however, the air pressure required is about 32 lb. gage while, in the other case, the pressure would be 140 lb. and the mean effective pressure required for the compression of the air (adiabatic) to 32 lb. would be about 20 lb., while, for compressing to 140 lb., the mean effective would be 50 lb. Then, comparing $1.83 \times 20 = 36.6$ with $0.88 \times 50 = 44$, it appears at once that the apparent cheapness of deep submergence is nullified or reversed, and other considerations determine what submergence is best.

While, as was said farther back, the higher the lift the greater must be the actual submergence, the percentage of submergence will be the other way. It has been recommended in some quarters that a submergence of 60 per cent be adopted in all cases, but better results are obtained by departing from this in both directions, going to 65 per cent for lifts of 20 ft. or so and down to 40 per cent for lifts of 500 ft. or more to secure the greatest delivery. This is in recognition of the augmented pipe friction when the vertical length of pipe to be traversed is so great.

The air lift is applicable to pumping in oil wells only under certain conditions, and when employed under other conditions the efficiency cannot be other than low. Owing to the comparatively great depths under which air lifts are obliged to operate in oil wells, the usual design of air lift must have a great submergence, that is, where wells reach a depth of from 2,000 to 3,000 ft., the submergence must range from 400 to 1,000 ft. to permit even a low degree of efficiency. An air lift efficiently designed would, of course, secure somewhat greater efficiency and could operate under much less submergence than 400 to 1,000 ft. If the quantity of fluid to be handled is small, it is not likely that a proper submergence can be obtained, and the efficiency will be low. Possibly, conditions would become such that there would be no flow whatsoever. By a small quantity is meant 100 bbl. per day and even up to 500 bbl. per day where conditions are unfavorable. The necessary submergence could be obtained by sinking the well to an additional depth of 400 ft. or more beyond the sand from which the oil is extracted, but this would be expensive and would not be economical except in relatively few instances; in fact it is considered hardly practical due to the probability of running into serious water troubles. Where the flow is 1,000 bbl. of fluid per day, the air lift usually can better any pump performance; and when 2,000 bbl. per day are to be handled, conditions are rarely such that any other means of pumping than the air lift can be employed.

As practiced in the Mid-Continent, piping layouts are simply 2- or 2½-in. lines let down into the well such distance that the running pressure set up by initial operating pressure will not exceed the pressure that may be carried on the compressor discharge with the gas engine at full speed and load. As rock pressure subsides and the working level of the oil drops, the air or gas line is lowered further, followed by the same procedure as rock pressure continues to become less.

One of Shaw's[1] examples of figuring the submergence, lift, and efficiency follows:

Depth of well	3,000 ft.
Length of tubing $D + L$	2,400 ft.
Working pressure, pounds per square inch	160.
Gas-lift factor, cubic feet per barrel	1,000.
Specific gravity of oil G	0.85.

Submergence for water $= 160/0.434 = 369$ ft.

Submergence for oil $= 369/0.85 = 434$ ft.

Lift $L = 2{,}400 - 434 = 1{,}966$ ft.

Air required at 100 per cent efficiency to lift 1 bbl. of oil (0.85) 1,966 ft. under pressure of 160 lb. submergence would be 112.0 cu. ft.

$$\text{Efficiency} = \frac{112.0}{1{,}000} = 11.2 \text{ per cent.}$$

A procedure for determining the amount of submergence with a compressor, is as follows:

1. Test the pressure gage to determine its error at about the pressure of submergence.
2. Start compressor slowly until pressure gage is stationary. The reading is that due to submergence, friction being eliminated by delivering only a little air.

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[1] SHAW, S. F., Methods for Determining Submergence and Efficiency in Air Lifts, *Nat. Petroleum News*, p. 65, March 9, 1927.

3. Speed up compressor to normal and note the increase of pressure, which is all due to friction between gage and eduction pipe at bottom of well.
4. Run compressor and pump at normal speed and delivery until pressure ceases to drop. The drop in pressure between 3 and 4 is due to the lowering of liquid level in the well.

It is believed that this procedure is applicable, with the necessary modification to the work, on oil wells where no physical submergence but an equivalent pressure submergence exists.

The Footpiece.—The subject of footpieces or flow heads is one about which little first-hand knowledge exists. Their function is performed far from the possibility of being watched and, so, more or less theoretical considerations enter into the problem. This is seen in practice where some experienced parties claim that footpieces, not being content with being useless, are actually detrimental while other authorities claim that their use assists the lift operation.

In view of the scanty data relative to gas-lift efficiency, it seems quite timely to call attention to an article[1] published by A. W. Purchase. An engineer desiring greater efficiency with either the gas lift or air lift should obtain this article which gives considerable data from that author's tests and experiments at water wells and, also, has a good bibliography of important articles and books on this subject.

The subject of the footpiece[2] on the gas lift is not receiving the attention it deserves. The flow of liquids follows natural laws which are not developed except by accurate experiment and observation. Each well must be studied to see what type of footpiece is essential. It may be unnecessary to have a footpiece. An example may be cited, however, where it would be a great advantage to have what might be called a "jet piece" which will admit a small amount of air or gas through the flow line or tubing at an elevation which would be above the lowest elevation at which the fluid stands when flowing.

Some general principles extracted from an article[3] describing one mixing device or footpiece are given below:

"The continued application of gas-lift systems has led to the development of flow devices, mixing chambers, or footpieces which are designed for the purpose of securing an intimate contact or admixture of the compressed gas and oil in the well, thus assuring the important frothing effect which tends greatly to decrease the weight of the column of oil to be raised."

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[1] *Proc. Inst. Mech. Eng.* (*London*), pp. 613–699, November, 1917.

[2] *Amer. Petroleum Inst. Bull.* vol. 7, No. 27, p. 108.

[3] Loomis Mixing Device Minimizes Gas-lift Back Pressure, *Oil Weekly* p. 30, Jan. 7, 1927.

"The footpiece is inserted and supported at a level slightly above that to which the oil is capable of being depressed when the well is shut in or dead; it is usually situated just above the top of the perforated casing. This may be, and usually is, the normal setting or position, though several installations of the gas-lift system have involved setting the footpiece at various depths below and above the perforated liner—in one instance, it being set 600 ft. below the top of the perforated liner. The position and character of the footpiece is such that after the oil outside the same is lowered to the level of the openings in the footpiece oil ports, the entrance of the natural gas through the openings is effective in producing an upward movement of the oil within the tubing."

"It is possible through the arrangement of mechanical auxiliary equipment to provide means for preventing the entrance of the gas at a point below the footpiece. This means that it becomes a simple matter to prevent the incoming gas into an oil well and under pressure from exerting that pressure upon the oil in the well and subsequently upon the formation bearing the oil. This detail is of importance in that the accomplishment of such installations is in direct dispute with the expressed views of many gas-lift engineers to the effect that gas under compression ejected into an oil well must of necessity exert that pressure against the formation. When it is possible to prevent a back pressure against the oil or rock pressure the advantages are obvious, unless it be desired to hold back any encroaching water, or to exert the much desired control of the formational gas through back pressure, thereby conserving the gas and its energy in the reservoir."

"Due to the predetermined level or position of the footpiece, the level of the oil in the well is above the level of the ports or apertures where the gases are permitted to enter the oil section. At the footpiece there is a comingling of the expanding gases and the warm oil and the subsequent intimate contact are conducive to the formation of millions of oil-gas bubbles, which enter into the formation of a column of an oil-gas froth, which, due to its greatly reduced specific gravity and weight, rises to the top of the oil tubing at the ground surface and the well 'flows.' Customary practice, of course, is to conduct the froth to the gas separator, remove the gases to gasoline plants for stripping, with the subsequent return of the gas, again under pressure, for purposes of continuing the oil flow from the well."

"In general, it is important that the footpiece should be installed at such a level in the well as to maintain as high a pressure at the mixer as is possible without setting up an undue back pressure, tending to prevent the oil from coming freely into the well. The pressure of the gas on the oil in the casing, outside the tubing, will cause the oil to rise to a point in the tubing above the outside level, this distance in feet corresponding to the head in pounds on the gas. As stated, the ideal point for the footpiece mixer may be slightly above the level taken by the oil in the casing when the well is shut in 'dead' and the pressure built up. After installation, the casing head being shut and the tubing head open, the gas is allowed to accumulate in the casing until the pressure drives the oil down to the level of the mixer; then, if the mixer has been installed at the proper level, the gas will begin slowly to mix with the oil in the tubing, forming some bubbles; then owing to the slight unbalance created by the lightening of the column, movement starts. As the top is approached, expansion produces larger and larger bubbles in the oil within the tubing."

"Since the gas, or mixture of gas and readily volatile hydrocarbons, goes into the oil under pressure and in a finely divided form, certain portions thereof, probably including those hydrocarbons in the paraffin series below propane, are absorbed by the oil. Liquid hydrocarbons may, in fact, be carried down to the mixer, to be volatilized by contact with the warmer oils therein. As the oil mixture rises higher in the tubing, thereby releasing the pressure, a column of constantly effervescing oil with a greatly reduced weight will actually foam over the top, causing the well to flow."

The point has been made that footpieces are used in water-lift work for the purpose of reducing the surface tension; if they accomplish this result with water, they should, likewise, be beneficial in oil work, where, even though the surface tension of oil is considerably less than that of water, some benefit and increase in efficiency should be obtained.

It can be shown mathematically[1] that slippage varies as the square root of the volume of the gas bubble. Slippage here means the movement of the bubbles relative to the containing oil; the bubbles ascend through the oil, due to the previously described buoyant effect. It is, therefore, desirable to reduce the size or volume of the bubbles as much as possible. The larger the bubbles the shorter the time required for them to coalesce; so, if the lift is working with large bubbles, the discharge will consist of alternate rushes of air and liquid but this effect will be diminished in proportion to the initial fineness of the bubbles aerating the column. The finer the size of the bubbles the nearer the expansion thereof will approach the isothermal type with its attendant high efficiency. It can, therefore, be seen that greater returns will be made in relation to the input energy by the use of a footpiece or mixer which will subdivide the input agent into as small divisions as possible.

Stated in another[2] way it is evident that the average size of the bubbles in the flow pipe must influence greatly the efficiency of the lift; such average size cannot be determined, but working results indicate that the relative average size of the bubbles bears a direct relation to the diameter of the hole or holes through which the compressed air or gas enters the flow pipe to mix with the oil.

Another practical way of looking at the matter is the one advanced by Pennington,[3] previously stated but repeated here as applying to this subject.

"An air bubble rises in liquid due to pressure or weight of surrounding liquid on the lighter air or buoyancy, and, due to the lesser specific gravity of air, the bubble rises. Traveling upward, surface of bubble in contact with liquid sets up friction between air and liquid. Friction being proportional to surfaces in contact, it follows that a unit volume of air in a single bubble sets up a definite friction quantity at definite speed. Hence, to divide the same air bubble into many bubbles means that greater surfaces are exposed for developing frictional contact areas. Take a bubble containing 1 cu. in. of air, at the pressure obtaining, whatever it is. The diameter of this bubble is 1¼ in. and the exposed surface of a truly spherical bubble of this size is 4.90 sq. in.

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[1] Ivens, "Pumping by Compressed Air," p. 102, 2nd ed

[2] Daw, A. and Z., "Compressed Air Power," Isaac Pitman & Sons."

[3] Pennington, Harry, Lift Efficiency Depends upon Skill in Design and Operation, *Oil Weekly*, p. 41, Aug. 19, 1927.

"Now, the same bubble may be divided into smaller sizes, and say we have divided it into bubbles ⅛ in. in diameter, each containing 0.00102 cu. in. of air. There will be then 1,000 bubbles each ⅛ in. in diameter. The surface of these 1,000 bubbles is 49 sq. in., or just ten times as much when finely divided, and the same amount of air then does far more work, for frictional work is proportional to the frictional contact areas."

Thus, footpieces that secure finely divided air bubbles without question can and do make an air lift more efficient than where, say, a 2-in. diameter opening admits air without an attempt at division into smaller surfaces.

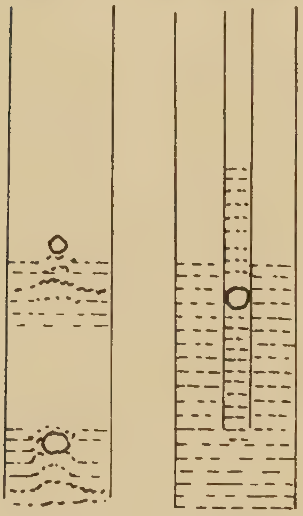

Fig. 93.—Action of free and confined bubble. (*Pennington.*)

Velocity affects slippage, for friction increases as the square of velocity in nearly all instances, although in air transmission the ratio is slightly more than the square of velocity. For instance, air traveling at 4 ft. per second develops slightly more than four times the friction of the same air traveling in the same space at 2 ft. per second.

It has been shown, also, that large air bubbles travel upward in liquid faster than small bubbles.

Hence, by these rules already established by experiment, smaller bubbles are more efficient than larger bubbles, and foot-pieces that secure finely divided air streams do deliver greater efficiencies.

And, with excessive frictional losses, not of bubbles traveling through liquid but of the mixture traveling up the pipe, the loss of power for compressing is excessive.

As stated by Pennington:[1]

"This is illustrated in Fig. 93 where a single bubble has been released and allowed to travel upward through liquid. This bubble reached the surface, traveling upward by reason of buoyancy, or pressure of liquid on the bubble, and there simply released. Traveling upward, the liquid was agitated by frictional contact of bubble with liquid, and by displacement of liquid by the bubble and the liquid surface was elevated when the bubble reached it. Thus, the energy contained within the bubble has been dissipated by friction and by elevating liquid slightly, and then lost for further useful work."

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[1] Pennington, Harry, Lift Efficiency Depends upon Skill in Design and Operation, *Oil Weekly*, p. 41, Aug. 19, 1927.

"But suppose that we insert a small pipe in the liquid, and release the same bubble within the pipe at the bottom end, as shown in Fig. 93. Due to the same buoyancy, and to pressure from the liquid outside the pipe, the bubble travels upward, and filling the pipe, the liquid above the bubble is elevated above the top of pipe. Another bubble will do the same. We find by tests, that this method, while serving to lift liquids, is exceeded in efficiency by the division of the same bubble into many smaller bubbles; the many smaller bubbles traveling upward, lift the liquid surrounding the bubbles, due to frictional contact, and the contact area being greater, slippage of bubble through liquid is less. By experiment, the writer has proven that large bubbles travel faster upward than small bubbles, and when traveling faster, develop more friction, but the difference is in favor of many finer bubbles traveling slightly at less speed."

Much effort is being expended by the field forces, particularly in the direction of the development of delivery heads or nozzles, along the lines and in the direction of the simple appliances used for siphoning liquids from one level to another, by means of the jet. After a review of this particular detail, the conclusion is necessarily reached that but little will be gained in any effort to apply the principles of a siphon or a jet head in the direction of increasing the efficiency of the lift performance. Undoubtedly, something will be gained over and above the bare application of an open tube in an open casing. Mechanical authorities have set forth the fact that some form of head that will break the stream of oil in spray is more effective than a complete disregard of this detail. But it is obvious that a jet head designed to accomplish some material advance in efficiency through the principle of induction or eduction jetting will fall short of any material accomplishment. It is probable that such a form of head might develop the equivalent of a few feet reduction in the total head or lift depth which must be sustained in operation. The reason will be seen along the following lines: the submerged delivery point for release of the flow medium, gas or air, may be thought of in lines parallel to delivery of steam in the cylinder of a reciprocating pump or engine between the piston and the head of such a prime mover, the strata pressure being comparable to the fixed head and the column of fluid to the movable piston in the cylinder of a prime mover. And one may follow the same lines of analysis from the breaking or initial flow point of such application to the usual subsequent condition after the head is broken and the column takes the form of a mixed spray flow of the fluid and the gas, the latter condition being analogous in every way to the former, except in the range of pressures that prevail.

A footpiece cannot correct a poor piping design. A correct piping design can operate at fairly high efficiency without a good footpiece, but the highest operating efficiencies and the lowest plant costs are obtained by correct design all the way through.

Early in the use of air, footpieces were offered as a means of obtaining high efficiencies, and, in a poor installation of piping, adding the footpiece and correcting the piping design secured high efficiency. But, removing the footpiece, unless it divided the air stream into bubbles, there was no appreciable difference in efficiency. But with a footpiece dividing the air stream, removing the same affected efficiency materially. Summarizing, it has been found that small bubbles and correct velocity in the flow piping are about the two most important factors in the action of a lift.

As to the form, type, or arrangement of the footpieces, there are as many different ideas as there are engineers working with these items of equipment. Attention is here invited to the fact that a number of footpieces, under various names and designations, have been patented. A number of these have been described in the technical press at various times.

Brundred[1] states, in regard to the use of footpieces, that . . .

"Gas lift, having had its inception in the old air lift for raising water, it was natural that any device which had been successful in lifting water would be tried in lifting oil. Experience to date has shown, however, that these devices, although in certain cases raising the efficiency in so far as it takes less volume of gas to lift a barrel of oil, in general create a slightly higher back pressure against the sand. This, as a rule, does not permit of the same volume of oil entering the hole and loss of production is often noted. The small gain in efficiency measured in dollars and cents of lifting cost per barrel is generally so small as hardly to warrant consideration, whereas the loss of production by the use of these devices must be given serious consideration."

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[1] Brundred, L. L., Practical Production of Oil by Gas Lift, *Oil Weekly*, Nov. 11, 18, 25, 1927.

"One of the most serious matters, however, arises from the use of jets or other patented flow devices in the hole. Many times the result is cut oil. Gas and oil passing through a restricted orifice, at high velocity especially where water is present, will cause the oil to be cut. Such trouble once experienced by the operator will generally cause him to return to the use of open-end tubing on the bottom."

"There are many devices in operation in the field, some of them giving excellent service, yet there are few cases available where the operator has compared his results on the same well first using the flow device and later using the open-end tubing. Data available on such experimental cases would seem to indicate that an equal or perhaps better efficiency has been obtained without the use of flow devices."

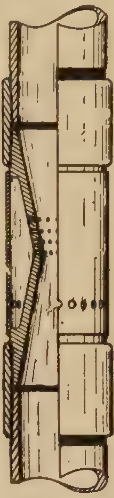

FIG. 94.—A "foot piece" showing application of the venturi throat. (*Loomis.*)

Consideration should be given to certain principles effecting the flow of fluids, such as the avoidance of sharp turns; providing stream-line sections, such as that of the venturi meter; where possible, avoidance of unnecessary constrictions and providing for easy access of the oil to the footpiece. There are cases where deflectors may be used to change the direction of flow at the bottom of the tubing, particularly where gas is injected through tubing; this is to keep the gas and fluid from impinging against the walls of the hole and to eliminate churning of mud where such exists in the well.

Some operators have adopted the practice of using inserted brass nozzles, consisting of ¼-in. bushings with a tapered hole of the desired size drilled therein at the angle of inclination decided upon for best operation. These nozzles are screwed into the threaded holes drilled either in the collars or in the pipe, depending upon the purpose for which designed. Any damage to the nozzle is repaired by the insertion of a new nozzle rather than the manufacture of a new length of nozzle pipe or footpiece.

In the use of the venturi-shaped footpiece, an example of which is shown in Fig. 94, one footpiece is so designed as to be

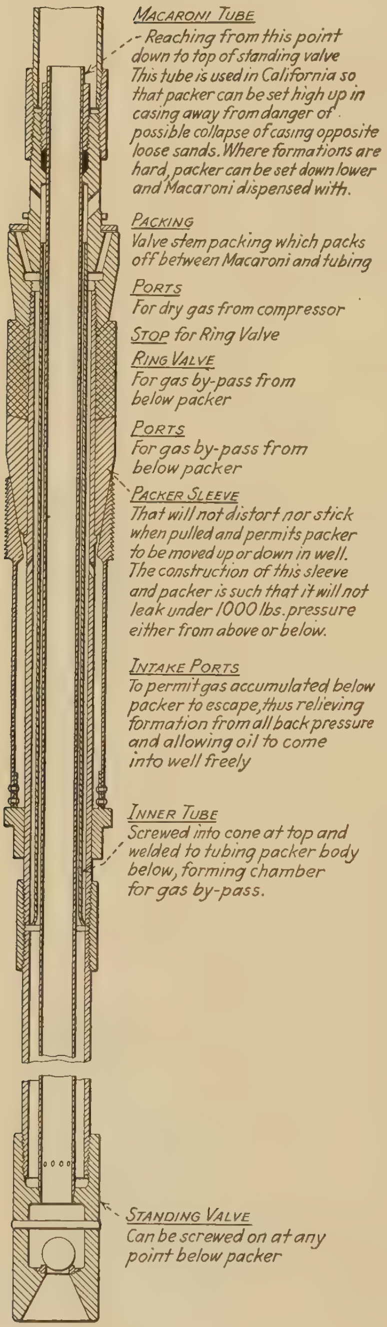
Macaroni Tube
Reaching from this point down to top of standing valve
This tube is used in California so that packer can be set high up in casing away from danger of possible collapse of casing opposite loose sands. Where formations are hard, packer can be set down lower and Macaroni dispensed with.
Packing
Valve stem packing which packs off between Macaroni and tubing
Ports
For dry gas from compressor
Stop for Ring Valve
Ring Valve
For gas by-pass from below packer
Ports
For gas by-pass from below packer
Packer Sleeve
That will not distort nor stick when pulled and permits packer to be moved up or down in well. The construction of this sleeve and packer is such that it will not leak under 1000 lbs. pressure either from above or below.
Intake Ports
To permit gas accumulated below packer to escape, thus relieving formation from all back pressure and allowing oil to come into well freely
Inner Tube
Screwed into cone at top and welded to tubing packer body below, forming chamber for gas by-pass.
Standing Valve
Can be screwed on at any point below packer

Fig. 95.

of use only in flowing through the tubing; another type must be used for flowing between the casing and the tubing.

It has been found from experience that a good workable footpiece which can be used under any conditions of flow, which is cheap, and which can be made up in the field consists of a 6- to 10-ft. length of tubing, closed at the bottom and perforated with ⅛-in. holes drilled in a helical pattern, the combined area amounting to from 80 to 100 per cent of the flow area of the gas inlet channel. This area is best found from experience with the individual well. It is believed that this type of footpiece is used more than any other; while it may not conform to all the theoretical requirements, it accomplishes the primary purpose of a footpiece in that the compressed agent is finely subdivided and mixed with the oil.

In case it is found necessary, for production reasons, to keep the input pressure off the producing formation, a packer may be set, above which are located inlet holes permitting the compressed input agent to enter the space between the flow pipe and a contained macaroni tube which is packed off at its top against gas leakage. The agent descends to the bottom of the annular space between the macaroni tube and flow pipe, entering the tube at this point. An example of this principle with the packer included in the equipment as manufactured by one company is shown in Fig. 95; also, see Fig. 113.

One important practical point which is often neglected is the use of spreaders in centering devices for keeping the footpiece in the center of the surrounding casing or hole; if the device is touching one side of the casing, its effective working possibilities are decidedly reduced.

In wells where excessive cooling takes place, or where, from other causes, a large amount of suspended wax is present in the oil, a certain amount of paraffin will accumulate and become attached to the walls of the pipe, even though the periods between flows are short. It is possible, also, that some of the paraffin particles become attached to the pipe as they come into contact with it while flowing with the oil from the well.

In wells that are flowed artificially by compressed gas or air, the same conditions are responsible for the deposition of paraffin, and the same methods of preventing and removing the accumulated paraffin are applicable.

In wells that are produced by means of the gas lift or air lift, trouble is often encountered with paraffin deposited at the footpiece or lower end of the eduction tube; and in wells where gas is jetted into the eduction tube at various points, paraffin accumulates at these places. Paraffin also accumulates along the walls of the pipe in the same manner, and as a result of the same conditions, as in natural flowing wells.

The accumulation of paraffin around the footpiece or end of the eduction tube is usually due to using excessive quantities of gas and allowing the well to pump off. When the well pumps off, the gas flows through the eduction tube and results in a local cooling. There is often sufficient cooling and evaporation at this point to cause the deposition of paraffin, even when the well is correctly operated. It also dries the film of oil on the pipe and allows the suspended paraffin to become firmly attached. The accumulation of paraffin around the jets in the eduction tube is the result of cooling caused by the gas at this point and of the fact that the constant wetting and drying of the surface immediately surrounding these jets allows particles of paraffin to become firmly attached to the pipe.

Velocity Considerations.—As stated in the section devoted to flowing wells, with a constant cross-sectional area of the flow pipe, be it casing or tubing, the velocity will increase towards the top of the well as the result of the increase in volume of the expanding agent.

The principle upon which the gas lift depends is not widely understood and many attempts have been made to flow oil wells by some process similar in action to that of an injector. In order to raise a particle of oil from the bottom of an oil well by means of an injector, it would have to be given an initial velocity sufficient to actually shoot the particle to the surface of the ground; or, in other words, the initial velocity would have to be equal to the velocity obtained by the particle of oil which had dropped or fallen an equal distance. Many footpieces and proposed methods of flowing oil wells have involved this misconception and, therefore, some prejudices against footpieces may have thus been obtained.

The objects to be obtained by use of a footpiece are well stated by Mr. Purchase. He shows that one of the principal sources of lost power in the use of the air lift is occasioned by velocity losses, such as eddies or other turbulences, and proposes that the entrance passage of a footpiece should be so designed as to avoid these losses. It is also shown that when the air or gas is introduced into the liquid in a finely subdivided state more efficient action is obtained than if the air enters in large bodies or gulps

The velocity increase which occurs upon the gas entering the rising column of liquid results from the fact that the pressure in the space occupied by the rising mixture is necessarily less than outside this space; otherwise there could be no flow.

It is reasonable to assume that, with a lift in steady operation, the weight of oil and gas passing any given point is constant in proportion but at increasing velocities as the top is approached, due to the expansion of the gas.

Brief consideration of velocity and density, as they actually occur in a 4,000-ft. well while flowing by means of the gas lift process, may serve more clearly to visualize conditions. If 500 ft. of gas is used to lift 1 bbl. of oil for a distance of 4,000 ft. through 2½-in. tubing and 400 bbl. of oil are being flowed daily, the velocity at the bottom of the tubing is about 230 ft. per minute or 3.83 ft. per second, while at the top of the tubing it is about 4,325 ft. per minute or 72.8 ft. per second. In other words, the speed increases due to the expansion of the gas which started upward under a pressure of about 350 lb. per square inch and reaches the top at about atmospheric pressure.

In considering the foregoing figures showing changes in velocity and volume, it should be remembered that the amount of gas per barrel of oil in those figures (500 ft.) is only about one-quarter or one-half the amount which is sometimes used and that the assumed daily output of the well (400 bbl.) is only one-third or one-half of the amount actually raised at many wells. The mixture coming from some wells, therefore, carries only a small fraction of 1 per cent of oil and has a velocity of 8,000 ft. per minute or more.

It is also interesting to note that immediately after the gas mixes with the oil at the bottom of the tubing, 500 ft. of gas per barrel of oil, the oil occupies about 20 per cent of the total volume, but when the mixture reaches the top, the oil occupies only about 1 per cent of the volume. In other words, the mixture starts with approximately the consistency of froth and emerges in the form of an oil-laden mist.

The figures of the above example are arrived at as follows: 2½-in. tubing has a diameter and cross-sectional area of 2.441 and 4.680 sq. in., respectively; 400 bbl. of oil equals 2,246 cu. ft. per 24 hr., or 1.56 cu. ft. per minute; 500 ft. of gas per barrel equals 200,000 per 24 hr. or 139 ft. (at atmospheric pressure) per minute. At a pressure of 350 lb. at the well bottom, this 139 cu. ft. of gas would be 5.84 cu. ft. Then, the total volume of oil and gas entering the lower end of the flow pipe equals 1.56 + 5.84 = 7.40 cu. ft. per minute of which the oil is 21.1 per cent by volume and the gas is 78.9 per cent.

The entrance velocity is then 7.4 × (144/4.68) = 228 ft. per minute. At the outlet of the flow pipe there is 1.56 cu. ft. of oil and 139 cu. ft. of gas or a total volume of 140.56 cu. ft. of which 1.1 per cent is oil and 98.9 per cent is gas. The exit velocity is the 140.56 × (144/4.68) = 4,325 ft. per minute.

Whether or not the flow should be made through the annular space between the casing and tubing or through the tubing very often depends upon conditions peculiar to the individual well. The point to be considered seems to be that of keeping the velocity of flow low, yet high enough so that there will be the least possible slippage, too much of which makes for excessive air or gas factors and poor results generally. To select a size of tubing that will permit the oil to be raised through the tubing is probably the best practice from one angle, in that friction losses will be less. This is evident when it is considered that in flowing between the casing and the tubing there are two comparatively large surfaces to cause friction, the outside surface of the tubing and the inside surface of the casing, while in flowing through the tubing there is only the inside surface of the tubing to consider. But it should be remembered that the friction losses vary approximately as the square of the velocity, so this consideration alone may dictate flowing through annular space rather than the tubing.

Assuming that the well is capable of yielding the oil, the production can be varied between wide limits, due to the control that can be exercised over the velocity of flow of the mixed oil and gas.

As a general proposition, the velocity employed is one of the main factors that determine the efficiency obtained, the term "efficiency" being used here in any of the ways as later defined.

At any section of the flow channel the velocity of flow is

$$v = \frac{Q + q}{A}$$

where

v = the velocity in feet per second.
Q = volume of oil in cubic feet per second.
q = volume of gas in cubic feet per second.
A = effective flow area in square feet.

Or, in terms of cubic feet of gas, barrels of oil, flow area in square inches, and velocity in feet per second, the formula is

$$v = \frac{(5.62Q + q)}{a} \text{ where } a = 144A.$$

In practice, there appear to be two critical velocities limiting the range of practical and economical flow. It is believed that the higher critical velocity is at the point where stream-line flow changes to turbulent flow, but this idea is based on hydraulic flow of a mass of liquid where, in the case of a lift properly working, the flow consists of a foam; it is possible that the upper critical velocity is due to some consideration other than viscous and turbulent flow. The lower critical velocity is believed to be defined by the slippage factor or as the point or range where slippage losses amount to a too great economical proportion of all the losses. This subject is open to considerable investigation; too little is known of actual conditions of flow of a froth and the critical velocities that enter into the problem. In some cases, it actually appears that even the most fundamental ideas of flow of fluids do not apply at times.

The selection of the proper size of pipe is based on the consideration of the quantity of oil to be produced; this means, of course, that such size is selected as will allow the supposed quantity available to flow with a reasonable velocity. Experience is the best guide, but in some cases even experience cannot enter into the solution of the problem, due to physical restrictions imposed by the condition of the well itself.

The theoretically best velocity is the velocity where the two curves, one plotted with friction losses against velocity, the other plotted with slippage and velocity as the arguments, intersect. Slippage losses vary inversely or increase as the velocity decreases, while friction losses vary as the second power and decrease as velocity decreases.

It is realized that by the use of surface controlled back pressure, secured in any of the many possible ways, the velocity of flow can be absolutely controlled but at the cost of production of oil. The main idea is to secure the most production possible and at the same time reduce the excessive velocities; this means large flow areas.

As a general proposition, when using a lift installation slow horizontal or nearly horizontal flow should always be avoided before the gas or air and oil have been finally separated, this mainly because of the probability of the formation of gas pockets.

The velocity head, or the pressure required to maintain the velocity of flow is given by the general formula for hydraulic flow

$$h = \frac{v^2}{2g}\frac{y_1}{y}$$

where

h = the head or pressure expressed in feet of liquid.
v = the velocity in feet per second.
y_1 = the mean density of the mixed gas and oil.
y = the density of the oil.

Another useful principle is covered by the following formula from Daw which gives the velocity of flow directly:

$$v = \frac{Q}{a}\left[1 - \frac{x}{l}\left(1 - \frac{1}{r}\right)\right]$$

where

v = the velocity in feet per second.
Q = volume of free air in cubic feet delivered by the compressor.
r = ratio of compression.
l = total length of discharge pipe in feet.
x = distance from top of discharge pipe to point where the velocity is to be determined in feet.
a = area of discharge pipe in square feet.

It should be noted that these are general formulæ and the first one is further generalized due to the necessity of using mean or average values rather than any definite value. But they are useful for securing some idea of the condition at some particular point of interest where the mean density of the mixture can be approximated. Realizing that the mixture of gas and oil varies from the liquid state at the bottom to a highly vaporized mixture at the top of a well, there is no formula or principle that can apply to the flow throughout the length of the column. The only source of real information on this point, as well as many others, will be the observations and the first-hand data secured from the wells in action; and no two wells will give the same results. But from this source some working principles will be secured through systematic investigation.

Owing to the high velocities, attendant losses, and difficulty of control of the flowing stream resulting from the expansion of the compressed gas through a rising main or flow pipe of constant cross-sectional flow area, the practice of using tapered tubing strings to give greater flow areas in the regions of larger gas volumes has been adopted. If the flow takes place through the tubing, the gradually larger sizes are installed towards the top of the string, while if the flow takes place through the annular space between the tubing and the casing, the larger sizes of the tubing are towards the lower end of the tubing string.

A general discussion of the ideas and principles entering into the use of tapered tubing strings, as given by Pierce and Lewis[1] at the Fort Worth meeting of the Petroleum Division of the A.I.M.M.E., is quoted here.

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[1] Pierce, H. R., and J. O. Lewis, Principles of the Air-gas Lift As Applied to Oil Production, *Petroleum Development and Technology*, p. 19, 1927.

"The use of tubing tapered downward is based upon the fact that as a gas approaches the top of a well the pressure becomes less and it expands and flows with increasing velocity. This velocity accelerates to the point that the friction becomes enormous in deep wells. At the bottom of the well, the upward flow of the oil and gas is relatively slow and probably much too slow for efficiency considered from the standpoint of slippage. On the other hand near the top of the well the flow is much too fast considered from the standpoint of friction; therefore, the need is for a design which in effect will increase velocity at the bottom of a well and decrease velocity towards the top."

"These considerations, long recognized, have lead to the design of tapered tubing, which has been applied for many years in air lift for water. The factors to be considered here are the practical design of tapered tubing under conditions met in the oil fields."

"To design a tube so there would be a constant velocity from top to bottom would mean that the cross-section of the tube should be increased upwardedly in proportion to the expansion of the gas but this is obviously impossible in deep oil wells, and in fact would theoretically not be efficient because it would make for extreme slippage. The design must, therefore, be a compromise between slippage and friction, and the downward tapering of the tubing must be based on an intermediate factor so that the most efficient design will be one with an increasing velocity upward but at not such a rate as in a straight pipe. In a well, especially a deep well, the use of tapered tubing is necessarily restricted to the size of the casing. There is a limit to the size that can be used at the top and to design a tubing in the correct proportions would make it far too small at the bottom of the well. As a matter of fact, in a well of considerable capacity, it will be found that the use of any tapering can be made only by sacrifice of daily production, as a smaller size of tapered tubing would so restrict the cross-section of the pipe as to unduly limit the flow and create high fractional resistance that would result in a high back pressure. This would be especially true where the end sought is the greatest daily production so that early in the life of the field it may not be practical to use any tapered tubing when the conditions are competitive."

"As the well gets smaller so that less volume need be handled, then it will become possible to use tapered tubing effectively and this will result in a greater mechanical efficiency, if properly designed, and also lower back pressures at the bottom of the well."

"When it comes to deciding on the taper, the engineer will have three problems; first, the practical limitation of the larger size that can be used at the top of the well; secondly, the smallest size that can be used at the bottom of the well to handle the volume of fluid without undue frictional resistance, curtailment of production, or back pressure; and, thirdly, the proper proportioning of the pipe as between the maximum size at the top and minimum size at the bottom. For efficient operations the graduations cannot be made at random because there should be a mathematical relation between the lengths of the different sizes which will evolve the best compromise between the factors of slippage and velocity."

"In connection with the use of tapered tubing, it may be pointed out that if this proves of sufficient importance, it would be possible in many instances to case the well with a string of pipe with larger sizes near the top that will permit taking advantage of this principle in deep wells, where the need for it is greatest."

The proportioning of the pipe becomes a matter of selecting the sizes which will allow the best working velocities as controlled by the slippage and friction considerations. The Ingersoll-Rand Company[1] gives data concerning the handling of water by a lift as follows: best entrance velocities are from 7 to 12 ft. per second (420 to 720 ft. per minute) and best discharge velocities are from 12 to 25 ft. per second (720 to 1,500 ft. per minute). In the case of the flow of oil, due to its lower density and, therefore, lower buoyant effects resulting in lower slippage factors, the best velocity figures will be between one-half to three-quarters of the above figures for water. This is a very important practical point which should be thoroughly investigated with a view of determining what the best velocities for oil are in practice.

Tapering as described above is used where wells have reached a comparatively low-production figure. By its use, however, the number of compressor machines employed per well have been reduced. Where wells become producers of the 50-bbl. type, it is thought that, by the use of the tapered or graduated tubing feature and individual volume control meters or pressure regulating control valves for each line leading to individual wells, several such wells may be profitably flowed by gas-lift methods and use a smaller number of compressors. Such work has been found practical on the West coast and no doubt the operators in the Seminole field will adopt such practices widely as the many wells drop off in oil production.

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[1] See The Air-lift System, Ingersoll-Rand Co. catalogue, Form 77, June, 1925.

It should be noted, at this point, that the use of tapered tubing is primarily for the purpose of reducing the velocity. This means in practice, that the slippage loss will increase, especially at the points of enlargement or change of size of the strings.

Theoretically, if a certain velocity has been found or decided upon as being the most suitable under the existing conditions, the proper diameter may be found from the formula

$$d = 12\sqrt{\frac{\text{Vol.}}{0.7854v}}\ \text{in.}$$

where

d = the diameter of the flow pipe in inches.
Vol. = the total volume passed per second.
v = the velocity in feet per second.

This formula will usually give some impractical size of pipe; it is, therefore, necessary to select the nearest standard size. It should be kept in mind that the normal production usually decreases rather than increases with time and, economically, it is probably better to select the next smaller size rather than the larger. This condition obtains also for the reason that, owing to slippage, the air or gas in the flow pipe has a greater average velocity than the oil, and, in consequence, the supply of air or gas occupies a smaller space therein than if there were no slippage.

It has been observed that the velocity ratio of 3 or even higher in some cases of straight tubing has been reduced to 2 and even lower when tapered strings were installed. The term "velocity ratio" as used above refers to the velocity at the top of a string or exit velocity divided by the velocity of inlet or the velocity at the bottom or entrance of the string.

The condition of the example previously calculated for the velocities obtaining in a string of straight tubing are assumed here and the main data for a tapered string are computed.

The assumed 400-bbl. well is 4,000 ft. deep and uses 500 cu. ft. of gas per barrel of oil at an operating pressure of 350 lb. per square inch. A.P.I. standard tubing sizes, without regard to strength considerations, will be used. It is assumed that the well is so cased that it is possible to use the 4-in. nominal diameter tubing as the top course of the tubing string. For simplifying the calculation, the expansion of the gas will be considered as isothermal, *i.e.*, $P_1V_1 = P_2V_2$.

The volume of the mixture at any point in the tubing is the volume of oil plus the volume of the gas which depends upon the pressure existing at that point. It will be assumed that the absolute pressure from the bottom to the top of the tubing decreases from a value of $P_1 = 364.7$ lb. to $P_2 = 14.7$ according to a straight-line relation, *i.e.*, the pressure decreases in direct proportion to the distance from the surface. The velocity at any point will then equal the total volume of oil and gas at that point divided by the flow area at that point. This statement is expressed by the formula

$$V = \frac{(Q_0 + (P_1/P_x)Q_g)}{A}$$

where

V = the velocity in feet per minute.
Q_0 = the volume of oil passing a given point in cubic feet per minute.
Q_g = the volume of gas passing a given point in cubic feet per minute.
P_1 = absolute pressure in pounds per square inch at the inlet (bottom) of the tubing.
P_x = absolute pressure in pounds per square inch at the given point.
A = flow area of tubing in square feet at given point.

Changes of velocity due to changing to the larger sized tubing are inversely proportional to the flow areas and, therefore, inversely proportional to the square of the internal diameters of the tubing. This velocity change is assumed to exist right at the small length of the tubing which is occupied by the swage or tapered nipple which is used to change from a smaller to a larger size of tubing.

The work is most easily done by computing the velocities for a string of one-sized tubing and plotting the velocity curve. At the point where the velocity reaches the assumed maximum best value decided upon, the next string of larger-sized tubing is added and the velocity graphically reduced inversely as the square of the diameter of the two sizes. The velocity curve is computed from this point and plotted; when the maximum best velocity is again reached, the process is repeated until the maximum-sized tubing allowed by the physical limitation of the well is reached. From this point on, nothing more can be done to keep the velocity within the desired limits without the use of back pressure,which practice is not considered in this example.

For this problem, the maximum best velocity will be taken as 600 ft. per minute or 10 ft. per second, for the purposes of illustration. The computation of the volumes, pressures, and velocities is tabulated on the following form. It should be noted that the curve representing the velocity for the one-sized string is merely the hyperbolic curve representing the isothermal expansion of the gas. It should be noted that, while the computations are made in terms of feet per minute, for convenience the curves of Fig. 96 are drawn for velocity in feet per second.

The volume of oil passing a given point Q_0 will be constant and will amount to 1.56 cu. ft. per minute for a production of 400 bbl. per day of 24 hr. The volume of gas at 500 cu. ft. per barrel of oil is 139 cu. ft. per minute at the surface at atmospheric pressure and is 5.60 cu. ft. per minute at the point of inlet at the bottom under an absolute pressure of 364.7 lb. per square inch.

Columns							
1	2	3	4	5	6	7	8
Depth, feet	Pressure, pounds per square inch	Q_0 cubic feet	Q_g cubic feet	$Q_0 + Q_g$, cubic feet	A (2½-in. tubing), square feet	V (5)/(6), feet per minute	V (7)/60, feet per second
4,000	364.7	1.56	5.60	7.16	0.0326	220	3.7
3,500	320.9	1.56	6.36	7.92	0.0326	243	4.1
3,000	277.2	1.56	7.37	8.93	0.0326	274	4.6
2,500	233.5	1.56	8.75	10.3	0.0326	308	5.1
2,000	189.7	1.56	10.8	12.4	0.0326	380	6.3
1,500	145.9	1.56	14.0	15.6	0.0326	478	8.0
1,000	102.2	1.56	20.0	21.6	0.0326	662	11.3
500	58.5	1.56	34.9	36.5	0.0326	1,120	18.7
200	32.2	1.56	63.5	65.1	0.0326	1,995	33.3
0	14.7	1.56	139.0	140.6	0.0326	4,310	71.8

The data of column 8 are plotted in Fig. 96 as curve A. The pressure data are plotted as the long dashed line with the argument of pressure at the bottom of the figure.

The velocity curve for the straight 2½-in. tubing intersects the 10 ft. per second line at about 1,150 ft. of depth. By changing to the next larger-sized tubing, *i.e.*, the 3-in. which has an internal diameter of 2.922 in., the velocity will be reduced in the ratio of the squares of the diameters or $(2.441)^2/(2.922)^2 = 5.92/8.54 = 0.695$. Therefore, $0.695 \times 10 = 6.95$ ft. per second will be the theoretical velocity in the bottom of the 3-in. tubing which is set at a depth of 1,150 ft.

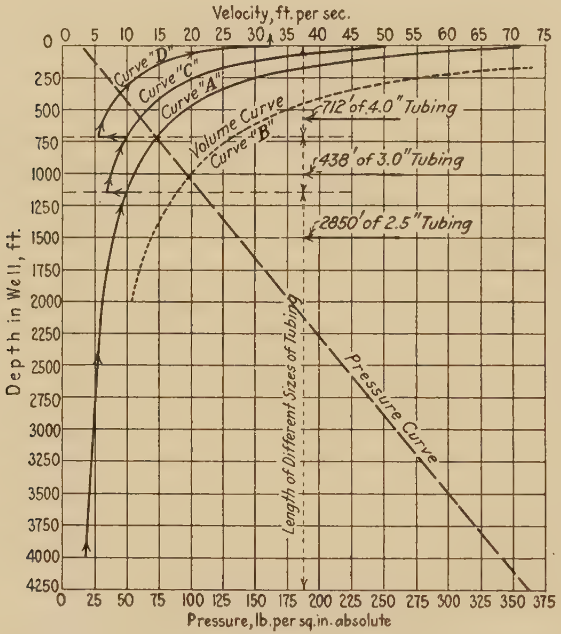

FIG. 96.—Typical velocity curves for tapered tubing strings.

The velocity from this point upwards through the 3-in. tubing is computed as follows, it being noted that curve B is plotted with the gas volumes (using the scale of velocity at the top) in order to find the volume of gas at the intermediate points where the velocity curve happens to intersect the limiting or best velocity line; also, some points intermediate to those of the first plot are found necessary:

Columns							
1	2	3	4	5	6	7	8
Depth, feet	Pressure, pounds per square inch absolute	Q_0, cubic feet	Q_g, cubic feet	$Q_0 + Q_g$, cubic feet	*A* (3-in. tubing), square feet	*V* (5)/(6), feet per minute	*V* (7)/60, feet per second
1,150	108	1.56	17.9	19.5	0.0466	418	6.95
1,000	97	1.56	20.0	21.6	0.0466	464	7.7
750	76	1.56	25.5	27.1	0.0466	582	9.7
500	55	1.56	34.9	36.5	0.0466	784	13.1
250	35	1.56	56.0	57.6	0.0466	1,240	20.7
100	23	1.56	88.7	90.3	0.0466	1,935	32.3
0	14.7	1.56	139.0	140.6	0.0466	3,020	50.3

The data of column 8 are plotted as curve C. Up to this point, Fig. 96 shows what the condition would be were but the two sizes of tubing, namely, the 2½ and 3 in., used or capable of being used. If this were the case, the exit velocity of 71.8 ft. per second would be reduced to 50.3 ft. per second or a reduction of practically 30 per cent. If but two sizes could be used it would be better to use more of the 2½-in. tubing than found previously, this amounting, in effect, to the use of a higher limiting velocity.

But returning to the original problem, it is seen that the velocity through the 3-in. tubing reached the prescribed limit of 10 ft. per second at a depth of 712 ft. so the string will be enlarged to the 4-in. size which is the last size permitted by the physical limitations of the well; 4-in. A.P.I. tubing has an internal diameter of 3.958 in. The velocity will be reduced from 10 ft. per second to $(2.922)^2/(3.958)^2$ parts of 10 ft. per second or $(8.538/15.67) \times 10 = 5.45$ ft. per second.

Repeating the computation for the 4-in. string from a depth of 712 ft. to the top:

Columns							
1	2	3	4	5	6	7	8
Depth, feet	Pressure, pounds per square inch	Q_0, cubic feet	Q_g, cubic feet	$Q_0 + Q_g$, cubic feet	*A* (4-in. tubing), square feet	*V* (5)/(6), feet per minute	*V* (7)/60, feet per second
712	74	1.56	26.5	28.1	0.0855	32.5	5.4
500	55	1.56	34.9	36.5	0.0855	426	7.1
250	35	1.56	56.0	57.6	0 0855	674	11.2
100	23	1.56	88.7	90.3	0.0855	1,055	17.6
0	14.7	1.56	139.0	140.6	0.0855	1,645	32.4

Plotting the data of column 8 as curve D and from the table above, it is seen that the end or exit velocity is 32.4 ft. per second, a reduction of 39.4 ft. per second or 55 per cent over the straight tubing and 17.9 ft. per second or 36 per cent over the two-sized string.

Summarizing this problem, by using 2,850 ft. of 2½-in. tubing, then 438 ft. of 3 in. and, of necessity, 712 ft. of 4 in. on top, the exit velocity is reduced 32.4 ft. per second. The velocities from the bottom to the top of the well are shown by the arrows. In practice, the considerations of slippage would dictate higher limiting velocities but the problem was worked out as above in order to illustrate a principle rather than give definite data or recommendations. That information will be available only from experience.

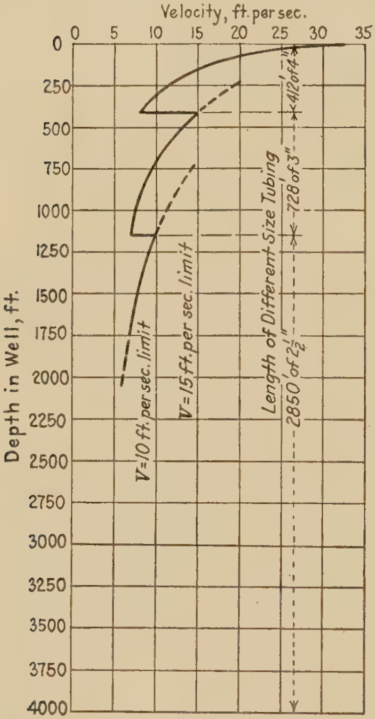

Fig. 97.—Typical velocity curves for tapered tubing strings and various velocities.

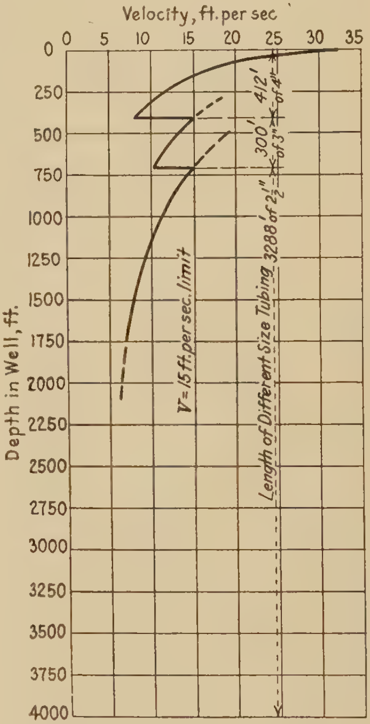

Fig. 98.—Typical velocity curves for tapered tubing strings and higher velocities.

One feature of practical installation for the condition of the above problem would be to limit the 2½-in. string of tubing to a 10 ft. per second velocity, the 3-in. string to, say, 15 ft. per second, and the 4-in. string with the final resultant, this for the purpose of reducing the slippage losses in the larger pipe flow areas. The end velocity will be practically the same. The graphical representation of this application is shown in Fig. 97. The use of higher limiting velocities, such as, say, 15 ft. per second rather than 10 ft. per second, will give results as shown in Fig. 98. Only those parts of the construction which exemplify the points under discussion are shown in Figs. 97 and 98.

The main point to be considered here is that the controlling factors in the use of tapered tubing are the diameters and, therefore, the flow areas that are possible physically, rather than the lengths of the different-sized tubing used.

The air lift is intended for steady work and not for occasional and frequently intermittent service. It is not to be stopped and started at any odd time like a common reciprocating lifting pump. Its efficiency is largely influenced by the correct adaptation, or otherwise, of the sizes of air pipe and discharge pipe to each other and to the rate of air delivery, the latter being entirely controllable, while the inflow of the fluid adjusts itself to the conditions provided. Nothing is thought of here but the relations of discharge pipe and air pipe to each other, it being assumed, temporarily, that the fluid is free to flow into the bottom of the discharge pipe as the lift takes it away. The speed of this voluntary and uncoercible flow of the fluid really determines the best working speed, and, also, within certain limits the possible working speed of the lift. As might naturally be supposed, the rates of flow in the pipes and corresponding actual deliveries of fluid will be more rapid for the low lifts and small actual submergence than for the high lifts and deep submergence, the greater length of pipe causing the greater retarding friction.

An interesting point is the number of the experimenters who have hoped to gain an advantage in the application of these methods through the use of high velocities, such as used in the steam injector or jet. It is seemingly obvious that, if a velocity great enough to have any effect was set up at or near the bottom of the hole, by the time this mixture of gas and oil had gained in volume due to the decreased pressure of the gas, the velocities of the surface would be beyond any practical limit.

Starting and Flowing Pressures.—A diagrammatic arrangement for the piping in an air lift, as it is some times employed in an oil well, is shown in the accompanying Fig. 99 in which *A* represents the casing of the well; *B* is the air pipe that is introduced into the well; *C* is the casing head through which the air pipe passes and above which it is tightly packed to prevent leakage of air; *E* is the discharge pipe which conducts the fluid from the casing head to the separator. The distance L from the casing head or point of discharge down to the fluid level is known as the "lift," or "pumping head"; the distance D from the fluid level down to the point at which the air is introduced to the fluid column or flow pipe is known as the "submergence"; as stated previously, the number of feet of submergence divided by the sum of the number of feet of lift and submergence is known as the "percentage of submergence."

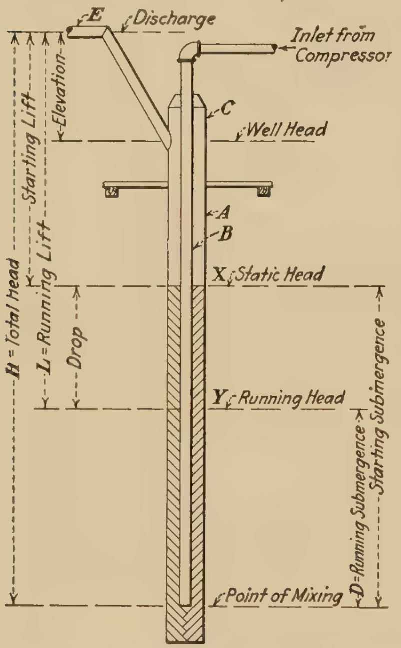

Fig. 99.—Diagramatic layout of air-gas-lift showing the relationship of the various factors.

In most wells, the fluid level will stand at a point such as X, or the static head, before air is admitted to the well; but, after the fluid begins to flow, the level will drop to a lower point, such as Y, where it will remain fairly stationary as long as pumping continues and conditions remain fairly constant. In such a case, the submergence at the beginning of operations would be the head drop plus D, and the lift would be L minus the drop. Before beginning operations, it is necessary to ascertain the starting submergence in order to insure ability to start, as the pressure needed to start the fluid flowing at this higher point might be greater than that for which the compressor was built. In this case, the air pipe would have to be raised the distance that would bring the pressure within the range of the compressor capacity. The pressure required to start water flowing is obtained by multiplying the feet of submergence by 0.434, to which is added the pressure equivalent to the friction loss due to the air flowing through the air pipe. If the fluid be oil with no mixture of water, then the pressure will be lowered by the amount corresponding to the relative specific gravity of the oil compared to water.

In some air lift installations in oil wells the air is admitted to the casing head by a connection to the line leading from the compressor and is conducted to the lower end of the tubing or flow pipe through the annular space between the casing and the flow pipe. The fluid is raised through the inner pipe which is connected to *E*, at the top of the well, through which it is discharged into the separator. Gas injected into this channel develops a direct pressure upon the surface of the oil between the two strings of pipe. As a result of this applied pressure, the oil, which, as a rule, normally stands at a level above the oil sand but varying with the rock pressure conditions, is depressed until it is forced into the lower end of the tubing together with some gas, and through this pipe is conducted to the surface. In the reversal of the procedure, the compressed gas is conducted below the oil level through the tubing string to cause the mixture of oil and gas to rise to the ground surface through the larger string of pipe.

The height of fluid in a well is ordinarily taken as representing, by its weight, the rock pressure in the formation. It has been found from experience that the fluid column, instead of consisting of the oil only, is usually aerated to some extent, varying with local conditions. This condition lightens the column and, consequently, the rock pressure is somewhat less than indicated by the height of fluid alone. With suitable corrections, the rock pressure may be found by ascertaining the height of fluid level. Other means exist for finding and even continuously recording the pressure existing at the bottom of a well.

As stated by Brundred:[1]

"To date most engineers and production men interested in the gas-lift method of producing oil have tried to evolve a set of laws based upon the old air-lift method of lifting water. It should be realized that the pressure per square inch exerted by a column of water is always constant, whereas the pressure exerted by a similar column of oil in a well is constantly changing. Oil is a mixture of hydrocarbons which, when agitated, is relieved of some of the natural gas held in solution in the oil. Furthermore, when standing in a well the natural gas coming from the sand so agitates this oil that at no time is it possible to determine the exact pressure per square inch exerted by this column at a given point in the hole. Even were such determination possible, it would be but a few minutes before conditions in the well had changed this pressure. For this reason it is impractical to take any of the laws of water lift and apply them to the lifting of oil or combination of oil and water."

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[1] Brundred, L. L., Practical Production of Oil by Gas Lift, *Oil Weekly*, Nov. 11, 18, 25, 1927.

The main information desired besides the rock pressure is the rate at which the formation will yield the oil against various pressures as represented by the different heights of fluid column. This information in graphical form is what is ordinarily called the "fill-up" curve. The data are secured as follows, as described by Bennett and Sclater:[1]

"In the method for determining this fill-up curve, the fluid level is lowered by bailing or swabbing, and by using a certain time interval the rate at which the oil enters the well to various heights is determined. The fill-up curve is determined under static conditions, hence these conditions change to some extent when the well is flowing by gas lift. While the fill-up test can be made in some instances, in many other cases it would be impossible to determine the fluid level with any degree of accuracy due to surging caused by the gas action. I believe that the fill-up curve, or build-up curve as it is sometimes termed, changes somewhat when the well is flowing by the gas lift."

The ability of fluid to enter the well after having been bailed down naturally decreases according to the differential between the formation pressure and the hydrostatic pressure represented by the volume of fluid standing in the hole.

Pierce and Lewis,[2] in discussing the pressure volume relations in a lift, state:

"Extensive experiments with the air lift in raising water have disclosed that for each depth, size of pipe, and quantity of fluid to be lifted there is a certain pressure and volume which will give the greatest efficiency of lift. If the pressure is exceeded, less air volume will be used, but the total horsepower will be increased and, similarly, if a lesser pressure is used, more air is needed, and the total horsepower consumed is greater. The submergence corresponds to relative pressure. The percentage of submergence or the relative pressure to the height of the lift is greatest in the shallow wells and becomes less and less with increasing depth of the well, though the maximum efficiency obtainable likewise becomes very much less with deep wells."

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[1] Bennett, E. O., and K. C. Sclater, Some New Aspects of the Gas Lift, *Petroleum Development and Technology*, p. 115, 1926.

[2] Pierce, H. R., and J. O. Lewis, Principles of the Air-gas Lift As Applied to Oil Production, *Petroleum Development and Technology*, p. 19, 1927.

"In the oil fields the pressure and volume used will result not only from the considerations of the maximum efficiency obtainable but also from consideration of the ends desired and the practical limitations; for example, if it is desired to get the maximum daily production, efficiency would be given little weight and all efforts would be directed toward increasing the rapidity of flow to the point where increasing friction placed a limit on the capacities of the eduction pipe. In another case it might be desired to hold a considerable back pressure on the well which might exceed the pressure of maximum efficiency, and in still other cases the declining rock pressure will necessitate the use of flowing pressures much below the air pressure of maximum efficiency. In fact, in each well the use of the air lift goes through a series of changes often starting above the pressure of maximum efficiency and finally ending at a pressure so far below the most efficient that an air lift becomes unusuable as a continuous process."

"Depth of the well obviously has a relation to both volume and pressure inasmuch as more foot-pounds work will be needed to lift the fluid the greater height, and also as friction and velocity will necessarily increase with the longer flow. This results in the need for greater pressure and volume with depth and in a lower and lower percentage of efficiency measured by the delivery of useful work."

"Size of pipe also has an influence on the pressure and volume of air needed. A pipe of large cross-section relative to the amount of fluid to be lifted will reduce friction but increase slippage and necessitate excess volume of air. On the other hand too small a pipe will cause excessive friction and result in high pressures with low efficiency."

"It may thus be seen that the pressures and volumes for maximum efficiency relate to the height of the lift and to the cross-section of the pipe relative to the volume being lifted. For each condition of depth and cross-section of pipe and relative quantity of fluid to be lifted, there is a certain relation of volume and pressure that will give the greatest efficiency, but the engineer applying the air lift in the oil fields should not only know how to estimate the point of greatest efficiency but also how to best meet other conditions, such as low rock pressure, or how to get the greatest daily production from a large well if that is desired."

Another matter of general nature which should be noted here is that, through some unforseen conditions, the pressure applied to a well may have some effects on the surrounding wells. A case is known where the pressure applied to the lift in one well caused an increased production in an offset well and finally a real blowout, the offset well experiencing alternate periods of flow and pumping, until the blowout occurred. Any possible effects on the neighboring wells should be watched for as they may help to explain the erratic action of the lift in a subject well.

It was brought out that the gas-air-lift methods work best in areas of cooperative production and where their use is wholly applied by all operators. Proof of this was shown in citing pumping and flowing wells which have increased after gas or air lift had been installed on a neighboring lease. This action, however, usually comes when enough pressure is applied in the hole to be greater than rock pressure; that is, when rock pressure decreases below the artificial pressure, thus causing reversed action in the sands.

Starting pressures are usually from two to five times higher than normal operating pressures. High starting pressures are due to the greater density of the column of unaerated fluid in the well. This fluid offers greater resistance to flow than the mixed column of gas and oil flowing through the eduction tube during normal operation of the gas lift. Because of the high starting pressures often required, auxiliary compressors capable of furnishing gas at pressures higher than that required for normal operation are usually installed. When gas is being supplied to a number of wells from a central compressor plant, a booster compressor capable of furnishing gas at pressures of 1,000 lb. or more per square inch is installed.

General statements have been made giving figures, or rather a range of figures, which have represented the starting pressures in some one field or group of wells. These figures are of value for that locality but could hardly be taken as of general occurrence. It is considered to be a simple enough problem to figure the theoretically required starting pressure, once the mean depth to the fluid is ascertained and the depth to the bottom of the tubing or rather the gas inlet, whichever way the well may be flowed. Some extremely high pressures, in one instance 1,400 lb., have been mentioned as the pressure which was applied in order to start the flow. It might be said, in passing, that the article mentioning the 1,400-lb. pressure stated that even this pressure failed to start the flow in this particular case.

High starting pressures, especially pressures higher than the existing rock pressure, are liable to do irreparable damage to a well. It is believed that as soon as the applied pressure plus the weight of the column of oil standing in the well exceeds the formational pressure, some of the oil will flow back into the sand or formation. Some installations are run with the idea that sudden application of pressure of short duration will not cause the oil to return to the sand in appreciable amounts, but, when the incompressibility of the oil column, no gas present, is considered, it would appear that if any mud, wax, or other foreign matter is present in the well bottom, it will be forced into the hole's surface sand pores. As a general proposition, it may be stated that allowing the starting pressure to exceed the rock pressure is extremely dangerous and subjects certain types of wells to very harmful effects. If there is any mud or paraffin accumulated in the hole and the direction of pressure differential is reversed, even for a short time, due to a high starting pressure, the walls of the hole are liable to become plastered and the drainage area partly closed. When normal flow is again established, the wells do not regain their original condition and must be cleaned, causing a delay and loss of production.

Different methods and appliances have been developed and used for starting the flow with comparatively low applied pressures. On this subject, H. C. Miller[1] states:

"In order to reduce the required starting pressure as much as possible, so as to avoid excessive high pressures which might injure many wells by forcing the oil back into the formation, provision is made at the casing head at many wells to reverse the flow of gas down the well. The gas intake line to the well is so arranged that by manipulating certain valves in the gas line, the gas is caused to flow first down the tubing and then down the annular space between the tubing and the casing. Often two or more reversals of direction of the gas flow are necessary to start a well. This method of starting the flow of oil is known as 'rocking.' The oil can be forced out of the tubing and aerated at a lower pressure than would be required were the direction of flow of gas down the annular space between the tubing and the casing and the attempt made to aerate the oil in the tubing, or to blow it out without first lightening it with gas. This is true because of the difference in cross-sectional area of the tubing and the space between the tubing and the casing."

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[1] MILLER, H. C., Mechanical Installations for Gas-lift Pumping, *Petroleum Development and Technology*, p. 85, 1927.

"For example, let us suppose that the fluid level in a well stands 500 ft. above the bottom of a string of 2½-in. tubing suspended inside of 6¼-in. casing. The total volume of oil within the tubing is 16 cu. ft. The volume of oil outside the tubing is 69 cu. ft. When sufficient pressure is applied at the tubing head to force all the oil out of the tubing, the fluid level outside the tubing is raised 116 ft. and the pressure necessary to empty the tubing of oil is 243 lb. per square inch if frictional losses are neglected and oil free of gas pockets and of 24 A.P.I. gravity is assumed. On the other hand, if the source of gas pressure is at the casing head, the oil in the tubing will rise 2,123 ft. and, again neglecting friction losses, the pressure required to force all the oil into the tubing will be 1,036 lb. per square inch. It is evident from the above that lower starting pressures are necessary when a well is rocked at the start or after a period of idleness."

Inlet gas connections should be so arranged that gas may be introduced through the tubing, or between the tubing and casing. These connections are made in order that the fluid column in the well may be rocked until the oil becomes sufficiently aerated to start the well flowing with the lowest possible working pressure. In deep wells, it is necessary to rock the column several times in order that the well can be started.

In the Panhandle field of Texas, the method used by the engineers of the Marland Oil Company for starting a well is as follows: Gas is first admitted to the tubing and allowed to pass up through the oil between the tubing and casing for about 1 hr. The aeration of the column is then sufficient to cause the mixture to flow from the well. As soon as the flow starts, the direction of the input gas is suddenly reversed, gas being applied to the annular space, and the tubing is opened to flow. The volume of the aerated oil in the space between the tubing and the casing is much greater than the volume of the tubing, so that a lowering of the level in the annular space by gas pressure causes the light mixture in the tubing to rise rapidly and flow out, thus starting the well.

By using this method, wells flowing from 3,000 ft. have been started on a maximum working pressure of 250 lb., whereas 600 lb. pressure is often not sufficient to "kick off" the same wells directly through the tubing. The working pressures in most of the wells in the Panhandle vary from 125 to 175 lb. The production of these wells ranges from 5 to 1,700 bbl. per day.

Brundred[1] treats the subject of rocking a well as follows:

"Difficulty at times is experienced in getting certain wells started in this manner, due to an extremely high static column of fluid existing in the well. Excessive pressures would be required at the sacrifice of compressor volume. When such exclusive pressures would be required and no paraffin or foreign material, such as rotary mud, is known to be in the well, the gas is introduced simultaneously into the tubing and casing at a high pressure. The fluid column in the well prior to the introduction of gas was held up in balance by the rock pressure. Gas, then, turned into the casing and tubing, acts like a piston and forces the oil back into the sand, and, thereby, reduces the height of this static column to a point consistent with the pressure applied at the surface. If the pressure is thus applied for a long enough period, a new point of balance will be reached, this point being the equivalent of the original height of static column, but now measured by the lowered fluid level plus the gas pressure exerted on top of the fluid. When this latter point of balance is reached, the gas is shut off from going into the tubing and the pressure is completely and suddenly released out of the tubing, leaving, however, the full volume of gas going into the casing head. This causes an immediate displacement of fluid up inside the tubing and down on the outside. Often this will cause the well to be kicked over or to start to flow. If, however, if fails to start, the action is recovered, the entire volume available is turned into the tubing and the pressure between the casing and tubing is completely and suddenly released. This causes the fluid on the outside of the tubing to rise quickly, whereas the fluid on the inside of the tubing is pushed down rapidly. Very often the well will start to flow within a few minutes after it has been reversed in this manner. Should, however, it fail to kick over it is again reversed, the gas in full volume turned into the casing head and the pressure completely and suddenly released from the tubing and so on, the well is rocked in this manner until it finally does start to flow."

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[1] Brundred, L. L., Practical Production of Oil by Gas Lift, *Oil Weekly*, Nov. 11, 18, 25, 1927.

"Each time the well is rocked, as just described, the oil, entering and discharging around the bottom of the tubing, as well as quickly passing the collars on the outside of the tubing, becomes agitated. This results in the column becoming more and more aerated. Therefore, with the same maximum pressure available, the fluid column, lighter with each reversal, will fill higher and higher until finally the well slowly spills over at the top."

"Caution in the use of this method is urgently recommended, as there are many wells where the complete and sudden release of all pressure in the casing might be the cause of collapsed pipe. Partial liberation of the casing pressure will accomplish the same result, provided that it is again quickly rebuilt and the process continued so as to obtain the maximum agitation of the fluid column."

"Where paraffin or foreign material, such as rotary mud, is known to be in the well, it would be inadvisable to apply pressure both through the casing and tubing simultaneously. This is due to the fact that sand, acting as a strainer, would be plastered, and, perhaps, permanently injured by this operation. However, the rocking method described above could still be used in cases of this kind."

"When the well first starts to kick over the casing will be full of such high-pressure gas as to preclude the infiltration of new oil into the bottom of the hole from the producing formation. As the static column rising through the tubing becomes exhausted, it is followed by a rush of gas in large volume and the pressure between the casing and tubing is gradually lowered. When this pressure gets below the rock pressure, the latter again forces oil into the hole. This oil cannot fill up around the outside of the tubing, as the gas, at a relatively high pressure, is rushing down the outside and expanding up through the tubing. Therefore, the small amount of oil being produced by the sand has but one outlet, namely, into the bottom of the tubing."

"Directly at the bottom of the tubing, then, the oil meets the gas traveling at high velocity. There the mixing of the oil and gas takes place and it rises through the tubing at first in a very fine fluid-laden spray. The rapid expansion of the high-pressure gas up through the tubing causes a further reduction in the pressure outside the tubing, thereby releasing part of the back pressure placed against the face of the sand. Naturally, thus relieved of this back pressure, the rock pressure begins to force more and more oil into the hole, such oil coming in contact with the gas and being atomized continuously. At this point, control of the volume of gas introduced becomes essential."

"The weight per 100 ft. of the fluid-laden spray is entirely dependent upon the amount of gas that is mixed with the fluid to properly aerate it. Therefore, control of this volume of gas must be absolutely accurate. This oil, in a fluid-laden spray, should travel directly from the bottom of the hole into the separator placed near the well. This can be accomplished with best economy only by carefully apportioning the volume of gas introduced, and, by automatic control, maintaining this volume at a constant rate."

"It has almost become an axiom that unless restricted considerably by friction as a result of too small a flow line, the more the volume of gas introduced the finer the spray, the lighter the column, and as a final result, the less the back pressure against the sand. Less back pressure, in general, means a more free flow of oil into the hole."

"To be sure there is a limit to the volume of gas which can be introduced. In the majority of cases this limit is represented by an increase in the flowing pressure with resultant loss of efficiency. From this it readily follows that by experiment only with the individual well can the proper volume be determined."

With the proper arrangement, a well can always be kicked off or started on circulation at a pressure equal to and, usually, considerably less than the natural formation pressure, or, in other words, the pressure at which the formation will take fluid or gas. The flowing or working pressure will necessarily be lower than this, and the difference between the two pressures will represent the differential at which the well is being operated and the comparative advantage which a particular well holds for the surrounding oil and gas.

The method and arrangement for starting wells on circulation, consists in piping the high-pressure gas line directly to the casing head in the usual manner—but providing a high-pressure by-pass for the purpose of introducing gas into the tubing. A high-pressure valve is always placed on the tubing head or flow line above the entrance of the by-pass. When starting the well, the tubing valve is closed and the by-pass opened enough to allow pressure to build up simultaneously within the casing and tubing, thus lowering the fluid level uniformly in both columns. As increasing pressure is gradually applied, the fluid is displaced until the top of the producing sand is reached, whereupon the formation will take gas, as indicated by the recording pressure gage either at the well or compressor station, when the pressure remains constant. At this point, the by-pass to the tubing should be closed and the tubing-head gate valve gradually opened, with gas still being admitted to the casing. Under this system, the amount of fluid which must still be displaced before steady circulation can be established is represented by the depth of tubing below the first formation.

This scheme represents a more complete displacement of fluid from the tubing than ordinary rocking, and even though formation pressures are in excess of practical pressures from the compressor, the same procedure carried out under a reasonable pressure, according to known conditions, should give the desired results in the higher pressure fields. These steps will at least overcome the necessity of running extra strings of tubing or casing with foot valves, as practiced by some operators who have been unable to start their wells by admitting gas to the casing only. Losing gas into formation, without starting wells, is the direct result of the column of fluid, standing in the tubing, overbalancing the natural formation pressure. The system described is particularly valuable in wells having comparatively low formation pressures.

In special cases where paraffin or silty mud deposits are apt to settle or exist in the bottom of a well, it may not be wise to back fluid or gas into formation, but, in other cases, there is a better chance of doing good rather than harm, from such procedure. Cases have been observed, in certain wells producing a heavy grade of oil, where a periodic injection of gas resulted in a stimulus to the production, presumably from the action of the gas in cleaning perforations, readjustment of loosely settled sands, or, most likely, from the effect of the gas upon the viscosity of the residual oil immediately surrounding the hole.

Another method called "superflushing" is used for starting wells on the gas lift in the Panhandle area. It consists of starting the gas through the tubing similar to the method previously described. After the flow has been started from the annular space, a large volume of gas is suddenly released through the tubing, expelling practically all the aerated fluid in the well. The direction of the flow is then reversed and the flow started through the tubing. This method requires less time and lower pressures than any other. A well requiring a normal working pressure of 180 lb. had been started in this manner on a maximun pressure of 230 lb. Flow is established into the tubing at the well head within 2 or 3 min. after superflushing takes place.

Rocking or reversing wells that will normally operate on pressures up to 175 lb. eliminates the necessity of installing high-pressure compressors for kick-off purposes and permits the construction of larger plant capacity for a given amount of money. In the Christmas-tree arrangement used by the Marland Oil Company, in the Panhandle district, connections are provided so that the flow may be obtained either through the casing or the annular space between the tubing and casing, the same as in California practice. Where a well can be put into operation on the gas lift by rocking and reversing, starting pressures higher than the original rock pressure in the sand can generally be eliminated.

In order to avoid in deep wells and heavy submergences the maximum ranges of pressure that are required to break the column and initiate the flow from the well, a more logical effort is being successfully applied now whereby the fluid column is broken and the flow initiated progressively through trip valves located at successive depths from the top. These trip valves, kick-off valves, or flow devices, quite a number of types of which are now available on the market, work with many different arrangements but with the one object, that is, the introduction of the compressed aerating gas or air into the flow column at some point or successive points which are uncovered by the fluid as it descends under the externally applied pressure, through either channel, this gas or air tending to areate the oil in the other channel from that point upwards. This progressive lightening of the rising column by sections enables the ultimate flow to take place through the original use of a comparatively low applied pressure, through either channel from that point upwards.

On one lease, special valves in the air line are located at intervals from the standing surface of oil to bottom of air line for lifting off successive heads of oil to avoid high starting pressures.

These valves, spring operated for closing, are so designed as to admit air into the oil 100 ft. below the oil surface and, when this

100 ft. of oil has been blown off, another valve below then opens, blowing off another 100 ft., followed by closure of the upper valve. This is followed successively down the well until the casing is evacuated of oil, and the well then operates like any other air-lift installation. This is a modification of the Stirling method and of the old Gulf coast method of starting wells. Rocking is not necessary and is not used and high-pressure compressors are not necessary for starting or operating.

Bell[1] described and summarized the effect of the use of what he calls a "fluid displacement pump" as follows:

"During the past 5 months, the Marland Oil Company of California has been trying a new device called a 'fluid displacement pump,' which has shown very encouraging results and is now being tried by several other companies. This device is run on the bottom of the tubing with either a packer or double string so that no gas pressure can reach the fluid. The fluid rises in the tubing through a valve until it approaches its static level and ceases to have sufficient upthrust to overcome the gas pressure exerted downward on the smaller gas valve, thereby opening the same and seating the oil valve as both are on the same stem. The gas which is introduced between the casing and the tubing enters the gas valve and lifts the column of oil in the tubing. When the top of the column of oil reaches the surface the gas starts to expand reducing its pressure so that the upthrust of the oil again opens the oil valve and seats the gas valve, repeating the operation. The results obtained with this device to date indicate that it or some similar device will go a long way toward solving many of the present difficulties in gas-lift operations."

"As a means of showing how improvements to the gas-lift methods may solve many of the present problems, the following notes are given on the advantages of the 'fluid displacement pump' tried out on the Marland properties:"

"1. *Reduced Volume of Circulated Gas Required.*—On one gas-lift well the gross gas-oil ratio was reduced from 1,227 to 424. This was typical of results on several wells."

"2. *Reduced Viscosity of Emulsion.*—Due to the fact that the gas does not mix with the oil to any great extent, the emulsions are less viscous and less stable."

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[1] Bell, A. H., Recent Developments in Gas-lift Methods in California Oil Fields, *Petroleum Development and Technology*, p. 136, 1927.

"3. *Increased Production.*—Wells changed from ordinary gas lift to 'fluid displacement pump' have shown increased production. This is due to elimination of gas pressure on the fluid."

"4. *Better Control.*—Due to the automatic control of the gas entry into the tubing, the flow of gas is easy to regulate without the use of other control devices."

A practice used in the air lifting of water was to install an auxiliary starting line which trapped the flow line and some point well above the operating inlet point, the idea being to aerate the water above the auxiliary inlet and then to apply the air to the operating inlet and, in this way, avoid the high starting pressure which would be required to force air into the flow pipe against the pressure of the entire column of water. By first aerating the upper part of this column, the pressure of the column at the operating inlet level is reduced.

While on this subject, it should be made clear that when the weight, or rather the pressure, resulting from the height of fluid column outside the flow pipe is spoken of as being the force which causes the flow of the aerated and lighter column of fluid inside the flow pipe, due to the lighter fluid having to stand higher in trying to balance the weight of the outside column, any artificially supplied pressure equivalent in amount to the pressure exerted by the fluid column will have the same effect. In fact, a greater artificial pressure can usually be supplied and, as long as it does not continuously force fluid back into the sand, the lift should work better; but, by the use of a too great pressure, the lift will be rendered inoperative.

The practice has been developed, in some cases, of deciding upon some arbitrary working pressure, usually that pressure which can be delivered by some compressor already on hand or some particular machine which it is desired to secure, and then setting the tubing at such depth that the applied pressure will cause the well to kick off and flow. The well is produced with this setting as long as economically possible; the tubing is then lowered to a point where the selected pressure will again start the oil and production is continued as before.

In many places where air is used, a suction is caused when the air is started and the fluid body cut in two, which results in a great danger of sanding the well, especially if the flow continues to head as from the natural result of the initial air force. When the air is started, the fluid body is cut in two, the bottom body serving as a cushion. When the top part is blown off, the pressure on the bottom is released, resulting in this suction.

In former lift practice, a system similar to common pumping methods was installed, having a working barrel attached to the bottom of the tubing with a standing valve placed as in a pumping well. When the air started, the standing valve closed and the fluid from inside was blown out through the tubing. Then pressure on the valve was released and the fluid pressure kept the valve open. The idea of the valve was to keep pressure off the casing and screen.

Operating gas pressures are extremely variable, ranging from 20 to as much as 500 lb. per square inch, or more in extreme cases, depending upon operating conditions. Operating pressures of from 125 to 300 lb. per square inch are common. Shaw[1] stated in regard to the Seminole conditions:

"Wells have averaged about 4,100 ft. in depth. The highest pressures in starting were about 1,000 lb. per square inch and since the small compressors are built for this pressure no trouble was encountered in meeting these high pressures. High-pressure fittings are employed altogether. The highest working pressures were about 450 lb. which, of course, declined gradually with the age of the well. The lowest pressure employed was about 50 lb. on a small well making about 10 bbl. per day, equipped with a string of tapered tubing. The majority of wells were flowed through the casing, however, and the average working pressure on these wells was about 190 lb."

The important factors determining the normal working pressure are the depth of the well, the rock pressure, the size of the flow tube or channel, the density, viscosity, and surface tension of the field, the volume of gas per unit volume of fluid raised, and the back pressure. As stated by Miller:[2]

"Some footpieces also have a marked effect on the operating gas pressure. A slight change in any one of these variables is reflected in the pressure necessary to operate the gas lift. It is, therefore, not surprising to find adjacent wells operating on widely different gas pressures. Operating pressures varying from 100 to more than 350 lb. per square inch have been noted in one small area where the wells were about the same depth and producing nearly equal quantities of oil from the same sand. Normal working pressures of 125 to 275 lb. per square inch for lifts of 4,000 ft. are common in California. In exceptional cases, however, operating pressures up to 650 lb. per square inch have been noted."

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[1] SHAW, S. F., Air-gas Lift Practice in the Seminole Field, *Petroleum Development and Technology*, p. 100, 1927.

[2] MILLER, H. C., Mechanical Installations for Gas-lift Pumping," *Petroleum Development and Technology*, p. 85, 1927.

The depth of the lower end of the eduction tube below the point of discharge influences more than anything else the gas pressure that must be employed, for this determines the height of lift. The working pressure may be reduced up to a certain point by additional aeration; that is, increase in the gas volume used will result in corresponding reduction in the density of the fluid in the flow tube and the working pressure will be reduced accordingly. This can be carried to a certain point—determined by the oil viscosity, diameter of tubing, and other factors—at which gas slippage becomes excessive and the efficiency falls off, or at which the growing pipe resistance offsets the advantage gained in reduced fluid density.

The lower end of the flow tube must, of course, be placed well below the static fluid level of the oil in the well; otherwise, the well will not be able to deliver an adequate volume of oil to the eduction tube. In general, the lower the tubing in the well the greater will be the volume of fluid that the productive formation is capable of delivering. This however, is limited by the pipe resistance.

Submergence governs pressure. Increased submergence means higher operating pressure but decreased air slippage losses and, consequently, smaller air volumes; decreased submergence means lower operating pressure but greater slippage and, therefore, greater air or gas volume necessary. Evidently there is an optimum point for submergence where the energy expended is the least. This can be found only by experimentation with each installation. The running pressure is less than the starting pressure, due to the already acquired momentum of the rising column of fluid, the pressure difference being equal to $0.434G(V^2/2g)$ and also due to the lowering of the running level head or, what amounts to the same thing, the pressures corresponding thereto.

The friction losses in the flow pipe, entrance losses, friction from source of supply of oil, all cause a lowering of the fluid level; if the pressure difference due to the momentum of the rising column be applied as a correction to the difference between the starting and running pressures, the drop in feet may be determined by multiplying the remaining pressure difference by 2.31G. This quantity will represent the sum of the above and other undetermined losses.

The size of tubing or flow line is governed by the volume of fluid to be lifted, the depth of the well, and the amount of gas required for flowing. But, as brought out by Foran at the Fort Worth meeting, the use of low pressures can be accomplished by the use of large flow tubing or small-sized casing and the introduction of comparatively large volumes of compressed gas or air. He gave the details of one installation where the flow took place through a 5$\frac{3}{16}$-in. string which had 300 ft. of 3-in. tubing installed at the bottom so as to give the mixture and initial working velocity.

Mr. Bennett,[1] when questioned relative to reducing the applied pressure on the formation stated that:

"The flow line is in the well and there is a certain operating pressure required according to the resistance of the fluid flow through the flow line. In other words, the pressure at the bottom of the flow line must be maintained at a certain point. If more gas is put through, it will aerate the column to a greater extent and the total column will weigh less than before on account of the large volume of gas. If it weighs less, it requires a smaller pressure at the bottom of the flow line and, so, by increasing the gas, it will require normally 1,000 cu. ft. of gas to raise 1 bbl. of oil. If run at 2,000, 3,000 or 4,000 ft., it would decrease the pressure materially and, by so doing, you would increase the differential from the formation back of the bore into the well and allow the well to produce for a longer period, because, when the working pressure balances off, you cannot use your gas successfully."

Circulation of an increased volume of gas tends further to lighten the ascending column and decrease the working pressure. Decreasing the working pressure permits new oil and gas to migrate towards the well. Limits are, of course, established when the frictional resistance of an increased volume of oil and gas mixture for a given sized system of tubing and casing overcomes the tendency to decrease the density. For maximum production, the size of tubing can be increased until limited by the casing in which it is run, and by the economic factor establishing the volume of gas which can profitably be handled for the recovery of a barrel of oil.

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[1] BENNETT, E. O., Discussion (p. 144) of "Some New Aspects of the Gas Lift" by E. O. Bennett and K. C. Sclater, *Petroleum Development and Technology*, p. 115, 1926.

As a matter of fact, in speaking of the flowing or running pressure, it is a quantity which results from the volume of input gas; in other words, it is the volume and not the pressure over which control is exercised. The pressure is an effect, not a cause.

The working pressure should be adjusted until the flow is uniform, without tendency to head or surge. Some operating engineers advocate a slight waviness in the differential line on the chart, this line being more of the nature of a line caused by vibration but of longer periods. Heading is due to a too great pressure on the oil sand or to a too small volume of input gas or air.

When the pressure required for flowing a well becomes greater than the existing pressure in the producing formation, the gas lift cannot be made to work, unless installations are made so as to keep the input pressure off the oil horizon. A study of pressure conditions existing in the wells and the probable working pressure that will be required for flowing a well will show the advisability of attempting to produce such a well by gas-lift methods. There are cases where such a small differential exists between the flow pressure and the pressure in the formation that the installation of a gas lift could be made to work but a brief period.

Expressing the foregoing statements in the form of an equation:

Let p = the applied pressure.
p_s = the pressure absolute for starting.
p_r = the pressure absolute for running.
p_0 = the atmospheric or back pressure absolute.
D_s = the starting submergence.
D_r = the running submergence.
G = the specific gravity of the oil.

Then the starting pressure without considering friction and other losses is

$$p_s = 0.434GD_s + p_0 \text{ in pounds per square inch.}$$

The remaining pressure is

$$p_r = 0.434GD_r + p_0 \text{ in pounds per square inch.}$$

If p is less than p_s, the air or gas cannot leave the channel through which it is conducted down the well; if p is much greater than p_s, the fluid will be forced back from the entrance to the flow pipe. In general, p must be sufficiently greater than p_s to start the flow, following which it must be reduced by $0.434G$ lb. per square inch for each foot drop of the fluid level from the static head level to the running head level; it will be necessary, then, to maintain p at a value only slightly higher than p_r in order to continue the flow, the excess being necessary to provide the velocity energy and the energy lost from the various possible causes.

The level of the fluid in a well before starting to flow with artificial pressure is higher than its level while flowing. In order to maintain a sufficient submergence while flowing, it is necessary to extend the tubing down into the fluid as deeply as possible, and, at the same time, to be sure that it is not so deep that the pressure will not start the well flowing. In many wells where the fluid stands high, this condition has prevented the extending of the tubing to a sufficiently low level for the best results, because the pressure to start the well would be too great.

When wells are exceptionally deep, it is sometimes necessary to raise the tubing and flow off part of the head, then suddenly lower the tubing and repeat until the working condition desired is reached. After the lowest position of the tubing is reached, it is desirable and necessary to keep continuous operation at all times to prevent the necessity of restarting which takes time, causes a loss of production, and is expensive. The Christmas tree can be supported on a wire line in the derrick, so that it may be readily swung out of the way when the position of the tubing must be changed.

Before the lift is in operation, there is the maximum column of fluid to be moved. The pressure obtaining in this column will vary directly with its depth, so, in case that a compressed agent pressure of 200 lb. is available, a column of oil of specific gravity of 0.85 and 543 ft. high would, theoretically, just balance this pressure. Any greater fluid height would overcome the input pressure. Take the case of some possible well where conditions were such that a drop of 500 ft. occurred; then it is possible that the 200 lb. input pressure would be more than sufficient to flow the well when once started, but it would be inadequate to start the flow. In addition to this greater starting head of fluid, there is the inertia of that fluid which must be overcome and which is no small item.

No general rules or figures can be given that will cover all cases, for in this matter alone is exemplified the idea that no two wells are identical propositions; the fluid levels before and after starting will be different as between any two wells, due to the different rates of oil supply from the sand and rate of production. It is, therefore, necessary to have the installation as simple as possible along with the ability to change the tubing depth as experience shows to be needed.

It has been found in practice that if the tubing is set too low, heading will result, owing to the fact that not enough gas is supplied to maintain a steady flow, the pressure applied requiring time in which to build up enough to force a gulp of gas down and through into the oil column. On the other hand, for a certain available pressure, the gas will blow through continuously and do little work if the tubing is set too high. This latter condition amounts to the so-called "pulsation effect."

The terms "starting" and "running pressures" refer to the specific pressures which are found to be necessary for the starting and maintenance of the flow in a lift installation. Pressure P, as such, is one part and volume V is the other part, which, taken together, constitute energy or the power to do work. Since it is the energy introduced into a lift, which, in the case of a naturally flowing well is indigenous to the confined gas occurring in or above the oil, that causes the well to flow, it can be seen that for a given amount of energy W, where $W = PV$, P can be reduced if V is increased and the energy W will remain constant or, *vice versa*, P can be increased and V decreased for a constant value of W. In compressor work, the investment increases with volumetric capacity rather than with pressure requirements. It would, therefore, appear that by the use of higher pressures and smaller volumes, lower first cost can be secured.

As shown previously, the work of lifting the oil is at the cost of the energy in the gas, exerted and freed by the gas expansion.

The back pressure on the productive sand in a well operated by the gas lift is equal to the static pressure of the column of fluid in the well below the lower end of the flow tube plus the gas pressure at the point where it enters the flow tube. Neither of these two pressures is ordinarily known precisely but can be estimated within reasonable limits of accuracy. The depth of the column of fluid below the lower end of the eduction tube is, of course, definitely known, but its effective density is uncertain since it cannot be known, at any given time, just what proportion of formational gas it contains. The gas pressure applied at the lower end of the flow tube may be estimated from the pressure at the casing head on the gas-inlet connection, but there is a certain loss in pressure, due to friction between this point and the lower end of the eduction tube, which can be only approximately estimated.

It is apparent that the back pressure maintained on the productive sand can be changed, within limits, by varying the size or the position of the lower end of the flow tube, or by varying the pressure and volume of the circulating gas. Lowering the eduction tubing or decreasing its cross-section, or increasing the pressure of the circulating gas or decreasing its volume, will operate to increase the back pressure on the productive sand, and *vice versa.*

Control of back pressure on the productive sand in this way offers a convenient means of conserving formational gas and increasing ultimate recovery. All of the advantages that go with a low gas-oil ratio may be realized by proper gas-lift control fully as well as by beaning. Indeed, under favorable conditions, the gas lift is a more efficient method of recovery, for the energy necessary to lift the oil from the well is largely supplied from outside sources and only enough gas is permitted to flow into the well with the oil to accomplish its expulsion from the reservoir sand. That is, most of the energy of the gas escaping from the productive sand is expended in forcing oil from the sands into the well, and the formational gas is called upon to furnish only a part of the energy necessary to lift the oil to the surface.

One consideration as between flowing the well through the tubing or the annular space between the tubing and oil string, other than the volume of flow requirements, is the matter of added back pressure on the producing sand. If the well is flowed through the tubing and the compressed gas is run down through the annular space, its pressure is added to the fluid pressure already on the sand. This condition can, of course, be avoided by using a larger string of casing or tubing inside which the flow tubing is run and sending the compressed agent down to the footpiece between the two strings, or by the use of a packer and a macaroni tube. If the well is flowed through the annular space, the compressed agent entering through the tubing and discharging into the oil through upward inclined nozzles, the sand is saved the additional pressure; in fact, the kinetic energy of the jets should act slightly to reduce the pressure on the sand, due to whatever ejector action is present. The back pressure on the sand is reduced by the use of large-sized tubing and large volumes of compressed agent at a low pressure.

One practical consideration requires the maintenance of enough back pressure on the trap or separator at the surface so as to supply the compressors with gas. This back pressure is, of necessity, carried by the lift installation throughout its working cycle. It has been proposed, as a measure to obviate this condition which, in some cases, may be the deciding factor between success or failure of the lift, to install booster stations or large low vacuum pumps on the gas-discharge line. This would, in fact, amount to the application of additional input energy to the lift in the form of negative compression of the agent. This means that the agent would have a greater range of expansion. As the gas or air rises with the oil, it expends a portion of its working energy, and the ideal theory of air-gas lift is to obtain the maximum energy from the gas before it reaches the flow tank.

One writer stated:

"Except for special problems dealing with water, sand, paraffin, or the like, the goal to be sought in the gas-lift operation is the lowest possible steady working pressure. For a given well the system which operates at the lowest pressure will result in the most fluid from that well. With this in view, it is often practicable to operate low-pressure compressors drawing gas in from the field to the extent that gas traps and return gas lines will be under several inches of vacuum. To an experienced operator the local conditions will determine the extent to which working pressures can be lowered. The principal sources of undue back pressure may be partially listed as follows:

"1. Restricting orifices, jets, or flow devices.
2. Undersized tubing for depth and volume used.
3. Restricted tubing-head connections.
4. Unnecessary pipe fittings, sharp angles, globe, and check valves.
5. High or undue pressures on gas traps.
6. Long, undersized, or indirect flow lines.
7. Elevated or poorly chosen tank settings."

"Each pound of decrease in the working pressure of a given well, where other conditions are equal, gives that well an advantage over its offset, whether the pressure on the offset be the working pressure of a gas lift or the weight of a column of fluid in the casing, as under pumping conditions."

Volume Requirements.—Some information relative to the volume of compressed air or gas required for lifting was given in the preceding section under the subject of pressure. As shown there, the volume of gas used is closely related to the pressures employed and, in practice, the consideration of the one subject includes the consideration of the other.

In general, the gas- or air-lift surface equipment installation requires only the compressor, lead lines to the wells with meters for volume control, and valves, hand operated or automatic, for controlling flow of compressed agent to the well. Air or gas is discharged into the tubing string at pressures ranging from as low as 150 lb. to as high as 500 lb. per square inch considering the field in general. The pressure is governed by the amount of gas required to cause the well to flow, and this volume, which in most wells is a delicate factor and must be carefully handled, is controlled within close limits either by automatic control instruments, or, occasionally, by hand manipulation of valves, etc. The volume of gas or air required ranges from 300,000 to as high as 1,000,000 cu. ft., though the latter high figure is exceptional, as is the low figure; 500,000 to 800,000 cu. ft. are better figures for the average amounts.

It has been found that there is a wide variation between different operators and at different wells in the amount of gas used per barrel of oil lifted. Some of the most efficient operators show oil being lifted with only slightly over 400 ft. of gas per barrel of oil.[1] On the other hand, wells are being flowed and use as high as 3,000 ft. per barrel of oil. It is also apparent that a high gas factor when the gas is introduced from the surface tends to hold the natural gas pressure in the sand, thus helping the well to maintain its fluid level.

The volume of gas circulated generally must be as large as the oil, passing up through the flow pipe, is capable of holding in suspension. Highly viscous oils and oils of low surface tension are able to retain greater quantities of gas in suspension without by-passing or slippage than those of lesser viscosity and higher surface tension. A flow pipe of small or moderate diameter offers less opportunity for by-passing of gas through the oil than one of larger cross-section.

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[1] *Mining and Metallurgy*, p. 235, May, 1925.

The volume of gas that must be circulated to secure the greatest returns per unit of input depends upon the volume of oil to be handled; that is, upon the productive capacity of the well and the rate at which the oil is flowed; upon the size of the flow channel and the position of its lower end with respect to the source of the oil; upon the surface tension, density, and viscosity of the oil and the solubility properties of the gas or air in the particular oil being flowed; the volume of formational gas accompanying each unit volume of oil; and upon the type of flow device or footpiece, or lack thereof, used in the well. In addition, the volume of gas required depends upon the proper submergence and the lift, assuming a given volume of liquid to be lifted. The number of compressions necessary to overcome the submergence and velocity of flow at the bottom of the flow column furnishes some of the essential factors for proper design of a gas lift. The extent of aeration of the fluid may be varied within wide limits, and the volume of gas necessary will vary accordingly. Within certain limits, the pressure necessary will be regulated by the volume of gas circulated, lower operating pressures being secured with higher gas volumes, and *vice versa.* All of these variables enter in greater or lesser degree in determining the ratio of gas to liquid in the ascending column of fluids.

Shaw[1] advanced the following information relative to Seminole practices:

"The quantity of gas or air required per well per day varied greatly, ranging from 400,000 to 1,200,000 cu. ft., the average being from 750,000 to 800,000 cu. ft.; 800,000 cu. ft. is used in the field in designing pressure plants. When production had declined to such an extent that the cross-sectional area between the tubing and casing was more than sufficient to accomodate the decrease quantity of production, operators continued to flow through the casing notwithstanding the fact that this method required excessive amounts of gas. This can be explained by the fact that most operators wish to maintain the established rate of production."

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[1] Shaw, S. F., Air-gas Lift Practice in the Seminole Field, *Petroleum Development and Technology*, p. 100, 1927.

Another writer stated:

"Many wells in California are made to produce oil at a total extraneous gas consumption of only 350 cu. ft. per barrel of oil. The average, however, of a large number of wells operating under widely diversified conditions and producing oil from depths of 3,800 to 4,500 ft. is somewhere between 1,200 and 1,500 cu. ft. of gas pumped in for each barrel of oil produced."

As the natural pressure in a well declines, a greater volume of extraneous gas can be circulated, causing increased aeration of the mixture in the flow line and a lower working pressure. When this method is used for prolonging the flowing life of a well, the tubing will generally be at or near the bottom. The lowering of the pressure causes a greater differential to be created between the flow line and the producing formation. This differential will prolong the time of flow of oil into the well. In no case should the differential be made any greater than is absolutely necessary to maintain reasonable production from the well. Excessive production, natural or otherwise, at any time is liable to damage the well.

The increased gas-factor method of prolonging the life of a well will permit more production than could be otherwise obtained. Where the gas is recycled through an absorption plant, additional gasoline is also recovered. The only additional cost in the method of using high extraneous gas factors is that required for compression. This, however, is small compared to the value of the additional oil recovered.

As brought out by Bennett,[1] this method is of especial advantage in producing deep wells where the gas lift is the only economical method which may be used. The curve of Fig. 100 shows the effect increasing the gas factor has upon the working pressure. As the amount of extraneous gas is increased the weight of the flow column becomes less. This continues until the friction due to the increasing volume of gas causes the working pressure to reach a minimum and rise. An observation of the curve will also show that production can be prolonged to the point where increasing the gas factor causes the working pressure to increase.

"In experiments conducted with one well, the gas factor was increased by an amount sufficient to cause the working pressure to drop from 105 lb. down to 18 lb. In so doing, the gas factor was increased from 1,800 ft. per barrel to 7,000 ft. per barrel. When the lower pressure was reached the oil was so greatly aerated that it was practically a fog. The high gas factor method of production should never be used where gas is not being recycled, as it will be extremely wasteful of gas and gasoline values. Keeping the gas factor as low as possible in wells being flowed by the introduction of extraneous gas recycled in connection with a gasoline plant is of secondary importance where it is desired to obtain the maximum amount of oil by gas-lift methods."

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[1] Bennett, E. O. Effect of Gas Lift on the Gas Factor and Ultimate Production, *Petroleum Development and Technology*, p. 158, 1927.

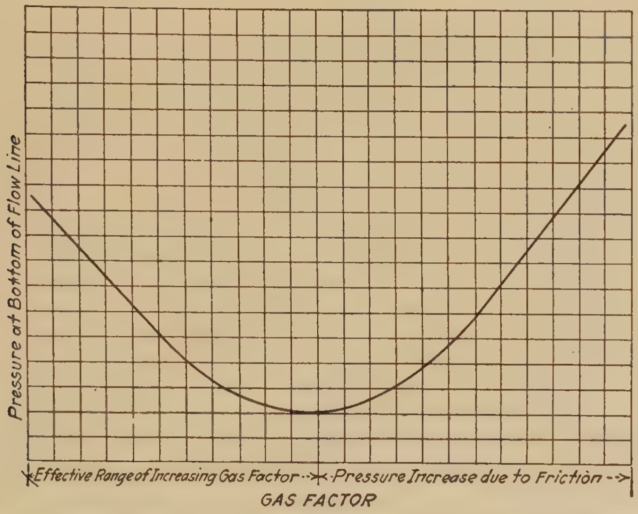

FIG. 100.—Diagram showing the effect on working pressure of decreasing the gas factor. (*Bennett and Sclater.*)

While, as previously stated, essential data of application of the method are available, there is one channel of information yet to be gained, *viz.*, more useful information with regard to the relation of flow-pipe area to volume of fluid to be lifted. It appears very probable that the method will be carried into practical usage where the volume of production to be handled goes much below that now thought practical. The present impression among producers is that when the amount of oil or fluid to be lifted from a well may drop below 100 bbl. daily, or such a matter, the old method of pumping will have to be applied. It appears more likely, at this moment, that this will not be the case; that the development of information and practice in this direction will adjust the areas conducive to successful lifting of small quantities of fluid to that degree whereby, so long as it is desired to maintain the residual pressure on the producing strata sufficient to lift the available oil, the method may be carried on successfully down to a stripper or range of a few barrels daily.

In general, a low fluid level is indicative of low rock pressure; this condition precludes the use of higher applied pressures and, therefore, a comparatively greater volume of gas must be used to supply the requisite energy. This means greater aearation and, therefore, large flow areas and compressor capacity. Recirculation of wet gas is a great help under these conditions.

The use of tapered flow strings or channels properly proportioned on the basis of velocities will reduce the required volume of compressed agent by varying amounts up to 50 per cent, this with velocity limits of 10 ft. per second for the entrance, up to 25 ft. per second as the advisable maximum.

Shaw,[1] in a description of the Seminole practice, stated:

"When flow was changed either to tapered tubing or tubing of uniform smaller cross-sectional area, a smaller quantity of gas was required but with a decreased rate of production, even though efficiencies with respect to gas-oil ratios were obtained. The lowering of fluid levels also accounted for relatively more gas being required to lift the oil . . . As gas-lift wells decline in production, the principal problem is to reduce the volume of air or gas used, thereby cutting down machinery necessary to operate the well, and keeping its operation on the profitable side of the ledger. The Carter Oil Company has been experimenting along these lines with tapered strings of tubing, and has been getting excellent results. In general, production has been maintained at about the same rate with the tapered strings, but in most cases only half the number of compressors has been found necessary after the change was made."

"The first Carter Oil Company well to try the tapered tubing idea was the No. 3 F Carter, in 24-9-6. This well has three strings of tubing, 4-, 3-, and 2½-in. diameter with the largest size on top. It is producing about 200 bbl. of fluid, of which 50 bbl. are oil. It is operated on a complete gas cycle of its own, the gas moving direct from the compressor to the well, through the separator and back to the compressor, with a small condenser plant to remove gasoline from the enriched gas. Since installing the tapered tubing, one of the two compressors formerly serving the well has been cut off, and production has remained practically unchanged."

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[1] Shaw, S. F., Air-gas Lift Practice in the Seminole Field, *Petroleum Development and Technology*, p. 100, 1927.

"The smallest gas-lift well, No. 4 Joe Carter, in 24-9-6, is also equipped with a tapered string of tubing. In this case, only two sizes are used, 2 and 3 in. The well, which never made more than 25 bbl. daily, has been flowing 10 bbl. a day on gas lift for more than a month. It is taking 10,000 cu. ft. of air per barrel of crude at from 50 to 60 lb. pressure."

"An electric-driven compressor is operating this well at a cost of about 7½ cts. per 1,000 cu. ft. For a 10-bbl. well this is quite expensive, and it is doubtful if the well is making much profit at present. It is estimated that compressed air costs 4 to 5 cts. per 1,000 cu. ft. when gas engines are used. This well would figure up considerably better at that rate of expense."

Heading in a lift is usually caused by a too small volume of gas being furnished to lift the oil continuously, the supply when finally accumulated acting in gulps; heading shows up on the chart as high and low points at intervals of minutes. Pulsations which, on the other hand, are matters of seconds' duration are due to a too great volume of gas being furnished. A recording meter is necessary in order to control the conditions of the lift to secure the best results, for, while heading can be heard when occurring, the other phase, *i.e.*, pulsation, cannot be found without the recorded action.

While on the subject of the volume of gas being used, the matter of the effects of the deviation of natural gas from Boyles' law as suggested by Dr. D. B. Dow should be considered. The metered high-pressure input gas passes through the lift and is again metered beyond the trap or separator. After allowing for the expansion, the excess is considered as being formational gas that has been taken out. Remember that, due to the deviation from Boyles' law, in other words, the greater compressibility, the actual volume of gas at high pressure is greater than that shown by the meter. This greater volume when expanded down to the exit pressure will then appear and, as stated above, is called "formational gas." The amount of deviation will vary with the characteristics of the gas itself, the wetter the gas the greater the deviation. It is, of course, quite probable that, at some of the higher input pressures employed, the less volatile constituents will be run as liquids. Then, entering as liquids and emerging as gas due to the lessened pressure, they would intensify the above-mentioned condition. One factor tending to lessen this condition is the fact that the quantity flowing varies as the square root of the differential and static pressures rather than directly as these quantities.

In a paper presented at the Fort Worth meeting of the Petroleum Division of the A.I.M.M.E., Foran[1] described a practice initiated by the Marland Company engineers. The following extracts are taken from that paper.

"In the Noodle Creek field in Jones County, the Marland Oil Company has made a radical departure from conventional tubing sizes and arrangements as well as plant design and methods of gas recirculation. Due to the curtailment in drilling operations in March, 1927, only one well was put on gas-lift production. This was a 1,400-bbl. well and was placed on the lift Feb. 4, 1927, 12 days after the well was completed. The production in the pool is from a lime formation at 2,510 ft. The initial rock pressure of this field was abnormally low, showing approximately 330 lb. per square inch."

"A 4-in. flow tubing was specified for the well but was unobtainable at the time, and a 5³⁄₁₆-in. casing was used as a flow string. The well was completed with 8-in. casing. Recording meters for gas measurements and pressures were installed at both input and discharge sides of the well. Air was forced down the 8-in. casing and the oil flowed up the 5³⁄₁₆-in. tubing in violent heads every 55 min. at the rate of 780 bbl. per day. This was unsatisfactory and a 2½-in. tubing was run inside the 5³⁄₁₆ in. and the gas forced down the 2½-in. tubing and the oil produced between the 2½ and the 5³⁄₁₆ in. The result was a steady flow at 1,085 bbl. daily with a gross gas-oil ratio of 905 cu. ft. per barrel and the input pressure at 195 lb."

"This arrangement was considered satisfactory and the following week additional air was forced into the well and the input pressure dropped to 160 lb. and the well increased its production for a short time. After the well had been on the air lift 3 months, the daily production fell below 500 bbl. and the input pressure had dropped to 124 lb. and the lifting gas-oil ratio increased to 1,600 cu. ft. per bbl. The well showed indications that it could not flow much longer under the 124-lb. input pressure, due to the rapid pressure depletion in the sand on account of this well being offset by three other producers. At this point it was decided that a radical change in both the tubing arrangement and compressors would have to be made in order to obtain the desired lower input pressure."

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[1] Foran, E. V., Mechanical Installations of the Gas Lift in Texas Outside the Gulf Coastal Region, *Petroleum Development and Technology*, p. 59, 1927.

"The high-pressure cylinder of a two-stage tandem-driven compressor was replaced by a low-pressure cylinder and the volumetric capacity of the compressor was doubled. Both the 5$\frac{3}{16}$ and 2$\frac{1}{2}$-in. tubing were pulled and a mixed string consisting of 275 ft. of 3-in. tubing as the lower part, and 2,226 ft. of 5$\frac{3}{16}$-in. casing as the upper part of the tubing was run in the well. The total tubing length was 2,501 ft. This placed the bottom of the tubing 8 ft. above the top of the sand."

"The well was then put on production and the input air pressure required to flow it was only 60 lb. Six pounds back pressure was indicated on the casing-head. This low pressure against the face of the sand resulted in an increase in the effective drainage area of this well, which, in turn, resulted in a decline rate much slower than before the change was made."

"Although the increased volume of input air on single stage compression gave results in contrast to those observed before the tubing change was made, it also presented some disadvantages, the greatest of which was the reduction of the gravity of the oil from 39.5 to 38° A.P.I., due to increased gasoline losses which were escaping to the air as there was no gasoline plant available to recover the vapors which tested 12 gal. of gasoline per 1,000 ft. The daily popoff to the air was 950,000 cu. ft. This indicated a loss of 1,140 gal. of gasoline daily."

"It was then decided to recirculate the output air-gas mixture from the well and allow any condensate which might occur after compression to return to the well instead of installing condensing coils following the compressor discharge. This process resulted in an immediate rise in the gravity of the oil from 38 to 41° A.P.I. and an increase of 24 bbl. of oil per day which represented the vapor losses in the air-gas mixture formerly escaping to the air. The gas was separated at the trap under a pressure of 7 lb. and delivered to the compressor intake at 5 lb. above atmosphere. This increased the compressor output 25 per cent above the free air capacity and resulted in a lower input pressure on the well. It is, therefore, apparent that this practice may open new possibilities to gas-lift operations which will result in a higher overall efficiency of ultimate production. This can be attained through the installation of a tubing pattern of such sizes and arrangement that wells producing up to 1,000 bbl. daily and at depths up to 3,000 ft. may be flowed at pressures which will require only single-stage compression."

The tabulated operating characteristics of this installation as given by Foran are shown below:

Daily Operating Characteristics, Marland Oil Company's No. 3 Mason, Noodle Creek Field, Jones County, Texas

	Daily production, barrels	Input pressure, pounds	Input gas, cubic feet	Output gas, cubic feet	Gross gas, cubic feet per barrel	Net gas, cubic feet per barrel	A.P.I. gravity	
Feb. 10	1,084	195	786,000	981,000	905	180	40.0	Used air for input.
Mar. 10	785	143	707,000	952,000	1,228	245	39.8	Used air for input.
Apr. 10	629	127	724,000	978,000	1,555	404	39.7	Used air for input.
May 10	484	120	731,000	947,000	1,956	446	39.5	Tubing compression changed May 13.
June 10	402	63	846,000	1,016,000	2,521	416	38.0	Air input single-stage compression.
July 10	364	60	947,000	1,024,000	2,812	212	41.0	Recirculation of wet gas at 5-lb. intake pressure at compression.
Aug. 10	321	55	1,065,000	1,150,000	3,616	265	41.0	No change in operation.
Sept. 10	315	53	970,000	1,045,000	3,318	238	41.0	No change in operation.

Tests conducted by the Blank Petroleum Company and experience in operation have shown that heading will take place when there is either too little or too much gas, provided there is oil in the hole. There is a maximum flow of oil from the well when the gas is cut down so that there is just a slight heading. As the gas is increased from this point, the line on the discharge chart will become smooth and then heading will again take place; if the gas is further increased, the well will cease to flow at all.

If there is not sufficient oil in the hole, however, heading will not take place, no matter how gas is regulated. At such times, the well may be spraying some oil, but the production will not be so high as when there is a slight heading.

Controlling.—The subject of the control of a lift installation usually refers to the hand or mechanical control of the input agent; another control, that of the back pressure on the producing formation, which is capable of being secured by means of the lift installation should be considered.

When the Seminole region went on gas lift, the main idea at first was to get the lift installed and the wells flowing. The systematic measurement and control which now obtains was a later development, the necessity for which was later recognized, studied, and the system installed; today, practically all wells using this system are equipped with gas meters which record the volume put into the well from the compressors, and most wells are provided with meters measuring the volume leaving the well. By taking the difference of these volumes and correcting for the greater compressibility at high pressures, the amount of gas supplied by the sand will be evident. Examples of this without correction and found in the figures given below. They are taken from wells in the Seminole field.

WELL NO. 1

	Cubic feet
Gas output	2,491,000
Gas input	600,000
From sand	1,891,000

Production of the well, 2,779 bbl. per day.

Gas-oil ratio	input, 216 cu. ft. per barrel. output, 890 cu. ft. per barrel.

WELL NO. 2

	Cubic feet
Gas output	2,167,000
Gas input	710,000
From sand	1,457,000

Production of the well, 2,146 bbl. per day.

Gas-oil ratio	input, 330 cu. ft. output, 1,010 cu. ft.

The matter of recording instruments is highly important to the efficient use of the lift equipment, and the most desirable results have been obtained by the use of two meters on each well, one to measure the input gas and the other to measure the output gas. The knowledge gained by a careful study of charts taken by such instruments gives the necessary information for the proper control of the well and pays big returns on the investment. A few companies operate their lifts without measuring the gas; this method seems very questionable, as they have little knowledge of the amount of the gas-oil ratio existing on their properties. There have been flowing wells at Seminole which stopped their flow when a string of tools was lowered into the hole for the purpose of agitating the well, and, in operations of this character, an accurate knowledge of as many underground conditions as may be ascertained seems very desirable.

As stated by Miller:[1]

"It is important that automatic recording gas meters and pressure gages be provided on the gas lines to the wells and on the gas discharge lines from the gas traps. The successful operation of the gas-lift method of flowing wells depends in a large measure upon the volume and pressure of the gas delivered to the well. The data obtained from pressure and volume-recording devices are invaluable to engineers and others upon whose knowledge and skill depends the successful operation of the gas lift. Continuous records of both static and differential pressures of the gas to and from the wells, recorded on 24-hr. charts, are the means of gaging the performance of the gas lift. Without these records, operators work more or less in the dark, and inefficient operation usually results. If there is no leakage of gas to low-pressure sands above the productive horizon in the well, then the ratio of this differential gas figure in cubic feet per day to the volume of oil in barrels produced daily is the formational gas factor, better known as the gas-oil ratio."

"Various types and makes of volume and pressure-recording devices are in use in the California fields. Each type is an orifice meter with a recording gage."

"Where the central-header control method of flowing wells by gas lift is used, the pressure- and volume-recording instruments on the gas intake lines to the wells are usually located in the header house. This arrangement makes it possible to operate the wells efficiently from this central location. At one installation in Southern California, one man per tour is taking care of over 20 wells, some of which are located a mile away from the header house. The outlet gas meters are always located at the gas traps where they measure the wet gas as it leaves the traps."

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[1] Miller, H. C., Mechanical Installations for Gas-lift Pumping, *Petroleum Development and Technology*, p. 85, 1927.

It has been found that a constant volume and pressure control to individual wells is absolutely essential and necessary to realize best results by the gas-lift methods. This is especially true where a definite pressure must be maintained to hold encroaching bottom water in check.

After a well has been studied and the proper-sized orifice installed, the well should operate steadily. As the production changes, due to natural decline, the size of the orifice must be changed, from time to time, to maintain the proper working differential. Orifice-changing valves, commonly used in the natural-gas industry, are valuable in this work and eliminate the necessity of by-passes in the installation.

The problems concerning the control of the volumetric input of a lift installation were stated by U. V. Thomas[1] and the following extracts are made from this article:

"Gas under suitable pressure is introduced in various specific manners beneath the liquid level in the well, the gas mixing with the liquid and forming a light mixed column which rises to the surface. The action of such a gas-lift system is uneven. At one time the gas may be more or less freely passing upwardly in the mixed column and consequently a given pressure will put more gas through the well than is desired. At other times conditions may be such that the gas is more or less trapped by the oil in the column, or temporary pressures may be developed in the well and then a greater pressure is temporarily necessary. However, if such greater gas pressure were constantly applied to the well, there would be great waste of gas during the times when the gas is flowing freely up through the mixed column."

"The opinion generally prevails among production engineers that in connection with the producing of oil wells by the gas-lift method, it is desirable to maintain a constant delivery of gas into any given well. That this can be accomplished is evidenced by the fact that several automatic devices for this purpose are used at the present time. However, it is becoming more generally recognized that a need exists for a device which, in addition to accomplishing the regularity of flow, will accomplish a varying regularity with variations in direct proportion to and as a result of the natural well pressure fluctuations."

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[1] THOMAS, U. V., Response to Pressure Variation Important for Gas Lift, *Nat. Petroleum News*, p. 88, Nov. 9, 1927.

"This control will regulate the feed of gas so that when a lesser pressure is required the gas will be fed under a correspondingly lesser pressure and volume, and when a higher pressure is necessary the pressure and volume will correspondingly increase."

"The solution, therefore, quite obviously lies in automatic pressure and volume regulation of the introduced flowing medium. Consider the effect of maintaining a constant differential pressure at an orifice in the delivery line to any given well. This does not imply that a constant volume of gas is passing, the volume being constant only so long as the static or line pressure remains unchanged, and it will be readily seen that if the same differential is maintained, the volume of gas will vary as well pressure variations are transmitted to and are directly reflected in the delivery line pressures; it naturally follows that the volume of gas into the well will decrease or increase as the well pressure rises or falls, respectively."

"The constant differential type controls will only admit sufficiently more or less gas to maintain the constant differential for which they are set and because of the comparatively slow reaction to well pressure variations, they permit the introduction of considerably more gas than is necessary for efficient operation and do not supply enough gas when the well pressure is high and an increased volume is desired."

"Obviously, if a finer degree of control adjustment can be automatically provided so as to permit varying well pressures to be met almost instantly with exactly the proper volume of introduced gas to effect an almost immediate predetermined proper relationship between well pressure and the flowing medium pressure such a condition approaches the ideal. In other words, regardless of the frequency of well pressure variations, the same predetermined pressure relationship can be maintained constantly over any period of time thus effecting a smooth, steady application of the gas-lift process to any well, under all conditions and with the need of personal attention eliminated."

"For highest efficiency, these factors should be maintained reasonably constant. At some wells, hand control has proved satisfactory and many operators in California are resorting to this method of maintaining proper pressure and volume of gas to the wells. At many large-scale installations of gas-lift flowing methods where the gas to the wells is distributed from a common header, the volume of gas to the individual wells is regulated manually at the header by opening and closing gate valves installed on the individual lines at the header."

"Some operators on the other hand prefer and use automatic control devices because they believe that mechanical pressure and volume control devices are more reliable and effective and that by their use more oil is produced at a lower cost per barrel. Several types of automatic gas-volume regulating devices are in use in the California oil fields. Two types will be described, the Foxboro and the Natural Gas Equipment Company's controllers."

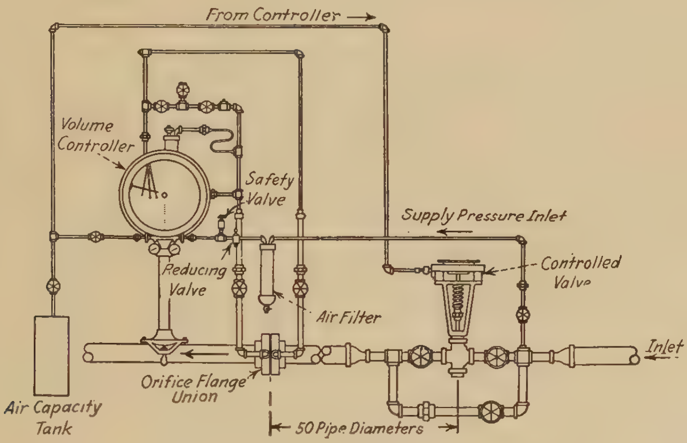
From Controller
Volume Controller
Safety Valve
Supply Pressure Inlet
Controlled Valve
Reducing Valve
Air Filter
Inlet
Orifice Flange Union
Air Capacity Tank
50 Pipe Diameters

Fig. 101.—Foxboro automatic volume controller.

"The Foxboro[1] gas-volume and flow controller consists of an orifice meter with mercury float-type differential recording gage and a volume control unit. The orifice meter operates on the well-known principle that when an orifice of smaller diameter than the line itself is placed in a pipe line carrying a liquid or gas, a drop in pressure is created between the upstream and downstream faces of the orifice plate. This drop in pressure, which is known as the differential pressure, is recorded on a 24-hr. clock-driven chart. The flow of gas or liquid through the pipe line may be computed from the recorded data on this chart. The volume control valve on lines carrying gas is gas operated through control mechanisms in the recording instrument. The rate of gas flow to the well can be automatically controlled and the pressure on the well kept uniform and the volume constant, by setting the index arm on the face of the differential gage to a differential pressure corresponding to the flow of gas desired. If the flow tends to increase beyond the desired point, the control mechanism tends to shut down the flow, and *vice versa.*"

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[1] Miller, H. C., Mechanical Installation for Gas-lift Pumping as Practiced in California, *Petroleum Development and Technology*, p. 92, 1927.

Figure 101 shows the diagramatic layout of the Foxboro automatic volume controller.

"The Natural Gas Equipment Company's differential regulators are also used in connection with wells flowing by the gas lift. This equipment, like the Foxboro, is used to maintain a constant flow of gas to the well. When a well heads and the pressure in the well goes up due to oil accumulating in the well above the inlet of the tubing, the device automatically increases the volume of gas to the well and reduces the heading cycles. Under opposite conditions, as when too much gas is being delivered to the well and the pressure is reduced, the volume of gas flowing through the line is automatically decreased. The rate of flow of gas to the well is accomplished by maintaining a predetermined difference in pressure between the upstream and downstream sides of an orifice installed in the gas line. The differential regulator is installed in the same line, either above or below the orifice plate. The high-pressure side of the diaphragm, which actuates the valve in the regulator, acts against the lesser gas pressure on the downstream side of the orifice and against the tension of a spiral spring. This spring may be set for the desired

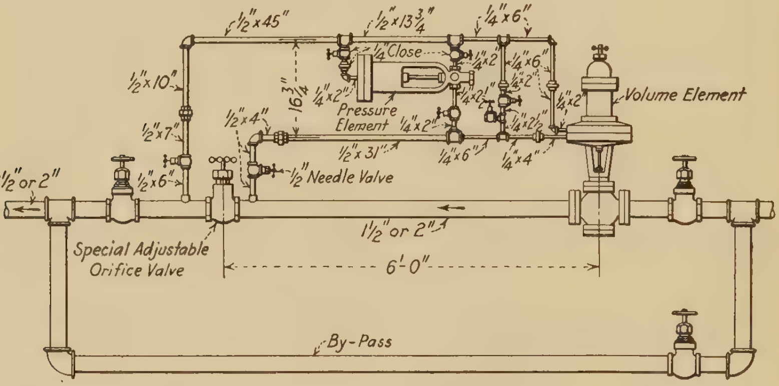
1/2"x45"
1/2"x13 3/4"
1/4"x6"
1/4"Close
1/4"x2"
1/4"x6"
1/4"x2"
1/2"x10"
16 3/4"
1/4"x2"
Pressure Element
1/4"x2 1/2"
1/4"x2"
Volume Element
1/2"x4"
1/2"x7"
1/4"x2"
1/4"x2 1/2"
1/2"x31"
1/4"x6"
1/4"x4"
1 1/2" or 2"
1/2"x6"
1/2" Needle Valve
1 1/2" or 2"
Special Adjustable Orifice Valve
6'-0"
By-Pass

FIG. 102.—The Thomas gas lift control.

difference in pressure of the gas. Changes in gas flow may be made by changing either the size of the orifice, or the adjustment of the spring tension. Any type of differential pressure recorder may be installed with this gas flow regulator when it is desired to record the differential pressure on a chart in order to compute the volume of gas flowing through the line to the well."

Figure 102 shows the diagramatic layout of the Thomas gas-lift control as handled by the Natural Gas Equipment Company.

There are systems and devices available and on the market other than those mentioned here and which are preferred by different companies. No recommendation relative to any one type is made here.

It is important to have control stations located at least 200 ft. away from the nearest well. This is to permit temperature equalizations before the gas reaches the well, instead of injecting the low-temperature gas directly into the well. The low temperature occurs where the gas is expanded through the control valve from the header system to the individual well lines.

A method of control which will give stable operation without the necessity of any automatic equipment is also being used in the Texas Panhandle. Its use is made possible by the physical law governing the flow of gas through small orifices under high differentials.

Automatic recording control instruments are extensively employed. In the centralized control house such equipment is protected during winter months by the enclosing walls and roof and the additional protection of steam coils for heating purposes is provided. In such an installation, the manifolds, through which the flow of compressed air or gas is directed to the individual well from a header arrangement, are located just outside the control room. This style of installation has the advantage of perpetual close observation of the actions of each individual flowing well, since the operators at the control house work in three shifts during the 24-hr. period. Hourly records are kept which provide for closer contact with the problems confronting the gas-lift department. Metering and control records are very beneficial in computing costs of operation, gas-oil ratios, and for comparative references when making future installations of the air lift. These instruments, which control the volume and pressure of the gas entering each well, permit the use of several compressors discharging into one header line, making it possible to handle several wells from a single compressor installation.

This work is similar to that which has been carried on by one engineering company in California for the past 3 years and is no innovation in gas-lift work. The device, as used on the West coast, is a valve, adjustable to a wide range of working pressures, which controls the volume of gas permitted to enter each well, at the predetermined pressure, by the simple regulation of a series of orifices of which it is composed, making possible the operation of several wells from one compressor plant, with all compressors working at the same pressure discharging into a header. The varying pressure of the gas entering each well is controlled and regulated by this type of valve at the well. Or stating it differently, any number of wells may be operated and flow at different pressures from one compressor by using the pressure regulator control valve.

The automatic volume control meter controls the volume on separate lines leading to separate wells, with all compressors in the pressure plant operating at the same pressure and discharging into a header line. This device assists the operator in getting away from the "compressor per well" type of installation and both are of value when the wells reach the low-production stage. Several small producers may be flowed by such pressure methods with fewer compressors. This permits the operator to move unneeded machines to other fields to flow other wells by the gas lift.

Following a well through all its stages of production, from the initial flowing period through to the period when formation pressure is exhausted: if the new well is active, the air or gas line cannot be installed, but, as soon as the well will permit, air lift may be installed with effective recoveries of oil. At this stage of production, back pressure is of material benefit in conserving rock pressure and holding back such pressure on the same, rather than releasing it, for the reason that rock pressure is the active agent in the formation for driving oil toward and into the well bore. By utilizing this pressure for that purpose, so far as possible, and lifting oil to the surface by means of compressed gas or air pumped down into the well, the highest total recovery can be made that is possible from the natural pressure found on the sand initially.

But when rock pressure has subsided to such point that operating pressure or pumped-in gas or air is equal to or exceeds the formation pressure, then the well may not produce so much as when operating pressure from compressors is held down to a lower point than the rock pressure then existing. At this stage, means must be taken to pump the well without placing back pressure on the sand if the same pumping equipment—air or gas—is to be continued, and there is no reason why the same pumping equipment cannot be used throughout the life of a well, provided, of course, that vacuum is not placed on the well.

Rock pressure in the Wilcox sand wells at Seminole is almost entirely absent and this lack of rock pressure has been the chief contributing factor to the relatively intense development and application of the gas-air lift system in this field. The force of the flow from many wells is derived from air- and gas-lift power, and with a load of 5,000 to 6,000 bbl. of oil daily flowing through the lead lines, etc., the force of the flow is naturally weakened to the point where back pressure may endanger stopping it.

In some fields it has been of advantage to use beans or chokes in the flow line, thereby securing a high back pressure and for a short time conserving gas, but it was found at Seminole that the wells in many cases would cease to flow where any form of back pressure was applied. The lowering of a string of 2- or 2½-in. tubing caused many a large well to cease flowing. The use of a bean is of advantage only where pressures are high, thus causing the well to act more in the nature of an artesian flow rather than as a gas lift. In this case, the fluid level stands very high, the oil is "squeezed" through the bean and production is greatly reduced. As soon, however, as the pressure has declined and the fluid level reduced to a point where the well is acting mainly as a gas lift, a bean causes the gas-oil ratio to increase to a high point. This effect is clearly shown by the results of the work of the Shell Company at Dominguez, Calif. The same effect of conserving the gas can be secured by employing the proper size of tubing through which to flow the well, and the gas-oil ratio does not then increase to excessive points when the fluid level is lowered.

As stated by Bennett:[1]

"The gas lift provides an excellent means of holding back pressures on a formation. The pressure on the formation is governed by two factors. One is the oil head H between the bottom of the tubing and the top of the pay. The other is the working pressure of the input gas. *H* is governed by the position of the tubing above the formation. The working pressure is governed by the size and length of the flow line and the relative amounts of oil and gas flowing."

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[1] Bennett, E. O., Effect of the Gas Lift on the Gas Factor and Ultimate Production, *Petroleum Development and Technology*, p. 158, 1927.

"When a well is equipped with a gas lift during the time it will still flow naturally the total pressure on the formation should be maintained at as high a point as possible. Small tubing for the flow line can be used to accomplish this or larger tubing with a choke or bean at the surface. Holding back pressure on gas-lift wells is not generally practiced, but good results may be obtained by so doing."

"The gas lift provides a means of increasing the flow rate of most wells where applied and is generally installed for this purpose. Such practice, however, will not generally give the maximum ultimate recovery. The latter condition can only be obtained by the use of pressure control; this condition is realized on account of the highly saturated condition existing at the bottom of the hole and the minimizing of the differential between the formation and the well. Whether a well is being produced by the gas lift or is flowing naturally, the effect on its ultimate production is controlled by the pressure conditions in the well."

"When considered as a means of back-pressure control the gas lift may be compared to natural flowing wells under back pressure. The formation below the flow line is of first importance and is governed by the same factors as a natural flowing well. The flow in the tubing, which is a means of controlling the flow differential, has, heretofore, been given much detailed discussion and is given secondary importance in this discussion."

To show the effects of control of the back pressure, by means of a flow bean in a gas-lift installation, Fig. 103, and the following discussion is included here, being taken from the paper presented by Bennett:[1]

"While the data of Fig. 103 cover only a period of a few months, it is typical of results to be obtained over long periods by pressure-control methods of operation. The curved line in the oil production curve of Fig. 103 is a normal decline for wells in the vicinity of the one referred to. It can readily be seen that after 17 days from the time back pressure was applied the decline curve and production curve crossed."

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[1] Bennett, E. O., Effect of the Gas Lift on the Gas Factor and Ultimate Production, *Petroleum Development and Technology*, p. 158, 1927.

"A study of Fig. 103 shows:

Total oil produced from May 18, 1927, to Aug. 22, 1927	327,777 bbl.
Total gas produced	199,004,000 cu. ft.
Average total gas factor	612 cu. ft.
Oil produced before applying pressure control	53,194 bbl.
Gas produced before applying pressure control	42,118,000 cu. ft.
Average gas factor	812 cu. ft.
Oil produced under pressure control	274,583 bbl.
Gas produced under pressure control	156,886,000 cu. ft.
Average gas factor	569 cu. ft.

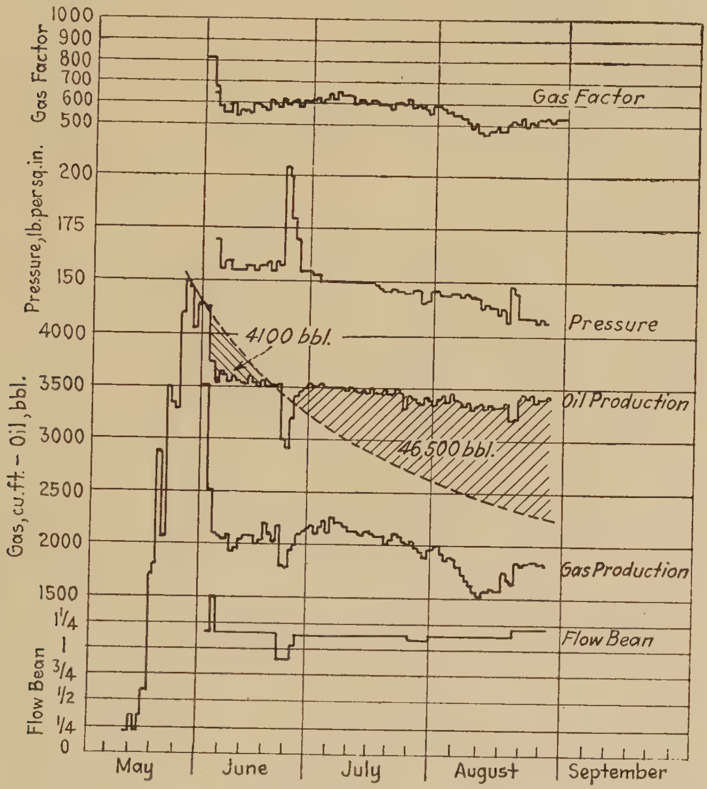

FIG. 103.—May 18, 1927-Aug. 27, 1927. Total oil produced = 327,777 bbls. Total gas produced = 199,004 M. cu. ft. Oil produced before pressure control = 53,194 bbls. Gas produced before pressure control = 42,118 M. cu. ft. Oil produced under pressure control = 274,583 bbl. Gas produced under pressure control = 156,885 M. cu. ft. Average gas factor = 569. Amount of gas conserved by pressure control = 66,124 M. cu. ft. a volume sufficient to produce 117,270 bbl. of oil at 569 gas factor. Estimated increase of commutative production to date = 42,400 bbls. Present estimated daily open flow = 3400 bbls.; pressure control = 2150. (*Bennett.*)

"The pressure control is responsible for the reduction in gas factor from 812 to 569 cu. ft., or 243 cu. ft. for each barrel produced. At this rate the total amount of gas conserved by pressure control is 66,724,000 cu. ft. At 569 cu. ft. per barrel this amount of gas is sufficient to produce 117,290 bbl. The cost of making this change in gas factor has been only the time required for making the study."

"The total estimated increase in cumulative production to date is 42,400 bbl. The present daily open flow rate of the well is 3,400 bbl. The pressure control rate is 2,150 bbl. or 63.2 per cent of the open flow rate."

"The gas lift, properly applied and controlled, will increase the ultimate production of a well. If not properly handled, it will decrease the ultimate production. Proper handling consists, principally, of the degree of skill practiced in maintaining back pressure on the formation."

F. W. Lake[1] of the Union Oil Company of California gave a thorough presentation of this subject in a paper, extracts from which are included here:

"The ultimate production from a natural reservoir is inversely proportional to the gas-oil ratios existing during the producing lift of the reservoir, in all accumulations of petroleum where, and during the period that, gas is the major expulsive force in the recovery. In other words, in the period during which gas is the major expulsive force the production will be increased if the gas-oil ratio is decreased, and *vice versa.* This condition controls in the large majority of the present producing districts."

"Eliminating natural conditions in a reservoir, which govern gas-oil ratios, such as the physical properties of the oil and gas, the physical characteristics of the reservoir strata and the original pressure and solution conditions in the reservoir, which cannot be controlled by operation practice, and also eliminating operating conditions which apply to the reservoir as a whole, such as well spacing, well locations, relative completion dates, various penetrations and drilling practice; there remains but one condition in each well which influences the gas-oil ratio and which is subject to control by operation practice, namely, the effective back pressure existing in the well opposite each of the producing strata. For each well at a certain time in its life there is an effective back pressure which will give the minimum gas-oil ratio, but this effective back pressure may or may not be within the limits determined by the various mechanical and economical conditions of actual practice. The maximum gas-oil ratio varies widely in different wells, in different areas, in different producing horizons, and in the same well at various periods during its producing life. The minimum gas-oil ratio obtainable may vary from as low as a few cubic feet per barrel to as high as several thousand cubic feet per barrel and in each case be a minimum for a certain well at a certain time."

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[1] LAKE, F. W., Relation of Air-gas Lift to Gas-oil Ratios and Effect on Ultimate Production, *Petroleum Development and Technology*, p. 173, 1927.

"Since for each well, gas-oil ratio control lies in the effective back pressure opposite each of the strata contributing to production, the various methods of production are more or less flexible in furnishing means for changing the effective back pressure to obtain the minimum gas-oil ratio. In flowing wells it is usually difficult to change tubing diameters and depths and hence two factors remain for the adjustment of the effective back pressure: (1) the regulation of back pressure at the tubing head by beans, flow nipples, or trap pressure and (2) the introduction of various amounts of gas in the casing head similar to gas-lift practice. In pumping wells the pumping depth, rate of pumping, and the pressure held on the casing head furnish better means for the variation of the effective back pressure to obtain a minimum gas-oil ratio than any other method of production. It is due to this characteristic of gas-lift operation that lower gas-oil ratios can usually be obtained, because the limits of effective back-pressure variation, which are controlled by the mechanical conditions of actual practice, are considerably extended."

"In gas-lift operation there are four convenient means for the control of the effective back pressure: Adjustments in tubing diameters, tubing depths, gas volumes circulated, and tubing-head pressures will permit considerable variation in the effective back pressure."

"Figure 104 illustrates conditions in the average gas-lift well. Gas is introduced between the tubing and the oil string at *A*, passing down between the tubing and oil string to the bottom of the tubing *C* and the oil and gas flowing up the inside of the tubing to the surface *E*. The casing-head pressure at *A*, less the pressure drop due to the friction of the gas flowing from *A* to *B* and plus the static head of the gas from *A* to *B*, is equal to the pressure at *B* which is the effective back pressure at the top of the first oil sand. The pressure at *B*, less the pressure drop due to the friction of the oil entering from the first oil sand and flowing from *B* to *C*, and plus the static head of the oil and gas from *B* to *C*, is equal to the pressure at *C*. The pressure at *C* is also equal to the pressure drop due to the friction of the oil and gas flowing from *C* to *E*, plus the static head of the oil and gas from *C* to *E* and plus the tubing-head pressure at *E* due to flow nipples, beans, or trap pressure. The pressure at *C* plus the pressure drop due to friction of the oil and gas entering from the second oil sand and flowing from *D* to *C* and plus the static head of the oil and gas from *C* to *D* is equal to the pressure at *D*, which is the effective back pressure at the bottom of the well. This pressure cycle can be varied within certain limits to increase or decrease the effective back pressure on the first oil sand and at the same time either decrease or increase the effective back pressure on the second oil sand by adjustments in tubing diameter, depth, gas volume circulated and tubing-head pressure. Thus the flexibility of effective back-pressure control in gas-lift operation is largely responsible for the means of obtaining lower gas-oil ratios than possible under other methods of operation.”

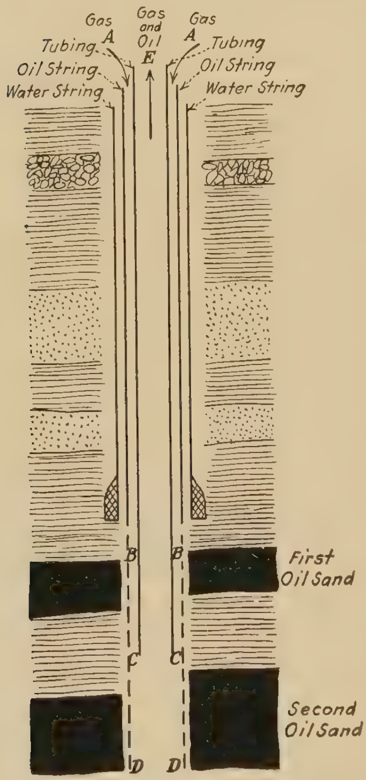

FIG. 104.—Conditions in the average gas lift well. (*Lake.*)

Lake gave in his paper different examples of gas-oil ratios as obtained in California practice. The discussions and graphs showing conditions in two wells are given here:

“Figure 105, Brooks well No. 2. In the beginning of 1925, this well was on the pump, producing between 180 and 200 bbl. per day. The production was declining while the gas-oil ratio was increasing more rapidly each month. In June, 1925, a 2 weeks’

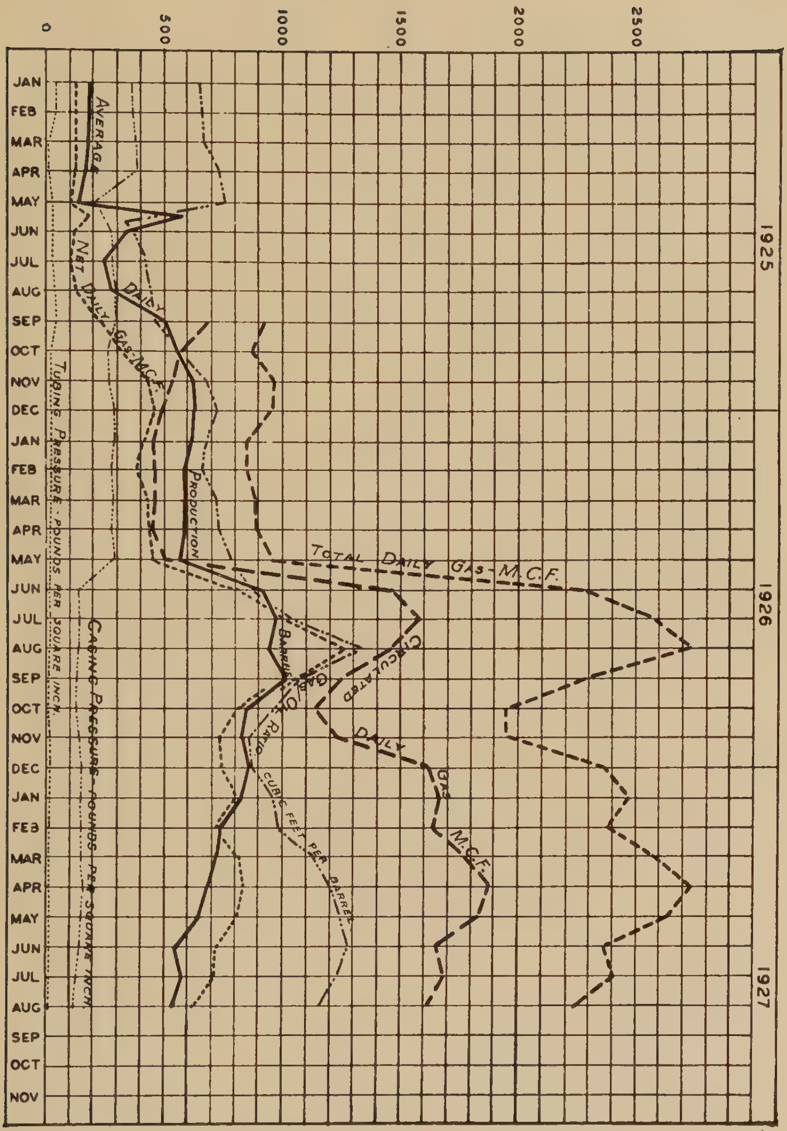

FIG. 105.—Union Oil Company of California. Brooks Well No. 2. Huntington Beach District. (*Lake.*)

test was made on the gas lift. The production was substantially increased and the gas-oil ratio decreased. After 2 weeks the well was put back on the pump up to the first of September, 1925. The pumping production during this time, while less than that obtained during the gas-lift test, was considerably more than the earlier pumping record and the gas-oil ratio, while higher than the gas-lift ratio, was lower than the former pumping ratio but was again increasing each month. When put back on the gas lift permanently in September, 1925, the gas-oil ratio increased with the increase in oil production but remained lower than during the first pumping period. Up to June, 1926, the well was being flowed through 2½-in. tubing at a depth of 3,800 ft. On June 1, 1926, the tubing was pulled and the well was flowed through 6¼-in. oil string with the top of the perforations at 3,470 ft., the gas being introduced between the 6¼ and 8¼ in. With this change, the oil production almost doubled the previous gas-lift production but the gas-oil ratio showed a tendency to increase rapidly. The increase in the gas-oil ratio was stopped by decreasing the amount of gas circulated until the latter part of 1926. The encroachment of water into the well began increasing rapidly until the well was producing 30 per cent water and the amount of gas introduced into the well had to be gradually increased in order to handle the increasing water production. The gas-oil ratio indicated a tendency to rise as long as the gas introduced into the well was increased. In June, 1927, a large portion of the water production was eliminated and the gas introduced into the well was decreased with a corresponding decrease in the gas-oil ratio. The drop in casing-head pressure in June, 1926, with the corresponding gas and oil increase, indicated a decrease in the effective back pressure throughout the producing horizon which increased the gas-oil ratio temporarily. However, by continuing the decrease in the effective back pressure by decreasing the gas volume circulated until the end of 1926, the gas-oil ratio was again decreased. From the end of 1926 to the middle of 1927, the gradual increase in effective back pressure was accompanied by an increase in the gas-oil ratio. During the last 2 months the decrease in the effective back pressure has been accompanied by a decrease in the gas-oil ratio. A change in the relationship between effective back pressure and gas-oil ratio during 1926 and 1927 is indicated. This curve illustrates the close relationship existing between gas circulated and gas-oil ratio."

"Figure 106, Morese well No. 3, in the same district, in the first part of 1925, was flowing naturally and starting to head.

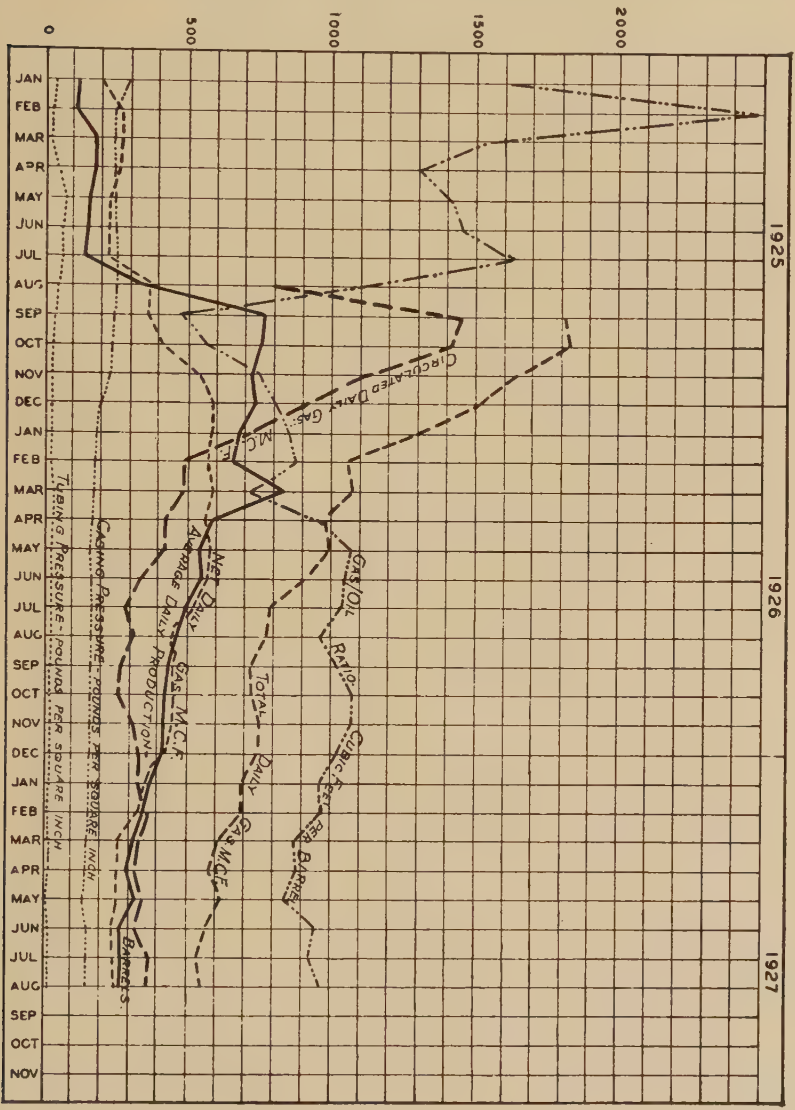

Fig. 106.—Union Oil Company of California. Morse Well No. 3. Richfield District. (*Lake.*)

The gas-oil ratio increased to 2,500 cu. ft. per barrel but was then decreased to an average of 1,500 cu. ft. per barrel by beaning the well until August, 1925. At this time, the well was placed on the gas lift and the production increased about four times. The gas-oil ratio was decreased by more than one-half. In the initial gas-lift operations, the gas-oil ratio increased steadily until adjustments were made removing all pressure possible from the tubing head and decreasing the gas volume circulated. From the middle of 1926 to the present time, the oil production has declined while the gas-oil ratio has shown a tendency to decline. This curve serves to illustrate the relation between tubing-head pressure, casing pressure, and gas volume circulated in their relation to the gas-oil ratio with the tubing diameter and depth remaining the same."

Heating the Input Agent.—H. C. Miller[1] stated:

"Preheating the compressed gas by steam before it enters a gas-lift well, in an ordinary type of heat interchanger, has made it possible to flow some of the low-gravity California oils. In Cat Canyon, Santa Barbara County, 11.5 A.P.I. gravity oil, so viscous that it will not flow at ordinary temperatures, is being flowed successfully from a depth of about 2,900 ft. by the use of heated gas. The compressed gas at 475 lb. per square inch pressure is heated by steam to about 200° F. in a preheater made out of a piece of 10-in. casing 4 ft. long. The gas passes through 38 tubes, 3 ft. long, which are welded in headers and enclosed in the preheater, and is delivered to the well where the temperature at the casing head is maintained at 190° F. The oil from the well has a temperature of 100° F. at the casing head."

"Surprisingly small volumes of heated gas are required to flow this oil, the viscosity of which has been appreciably lowered by the heated gas. Two wells, producing respectively 275 and 350 bbl. of oil daily, are being flowed by 330,000 cu. ft. of heated gas a day at 500 lb. per square inch pressure. This volume of gas is being furnished by one compressor."

"Some low-gravity oils in California have also been successfully flowed by preheated air. One well in particular, when flowing through 3-in. casing from a depth of 2,000 ft., flowed 250 bbl. of 16 A.P.I. gravity oil a day with 340,000 cu. ft. of air at a temperature of 190° F. When the temperature of the air was raised to 300° F. and the tubing diameter increased to 4 in., production rose to 325 bbl. at an added consumption of only 60,000 cu. ft. of air per day. The normal working air pressure in both cases was 240 lb."

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[1] Miller, H. C., Mechanical Installations for Gas-lift Pumping, *Petroleum Development and Technology*, p. 85, 1927.

"Many gas preheaters are 'home-made' affairs. Those that have come to the writer's attention in addition to the one described above, were made of used 11⅝-in. casing about 20 ft. long. A coil of 2-in. pipe, bent so that the gas or air passing through it made three complete passes from end to end of the casing shell, was inserted inside the casing. The ends of the coil passed through metal heads welded at the ends of the casing. The air or gas therefore traveled a distance of nearly 60 ft. inside the heater. The steam which surrounds the 2-in. coil enters the casing near one end through a 1-in. nipple and exhausts through a similar size nipple at the opposite end."

"Few California wells give trouble because of the paraffin content of the oils. Where paraffin has deposited in the eduction tubes in a few wells operated on the gas lift and has reduced production by decreasing the effective inside diameter of the tubing, preheating the gas has been beneficial in preventing the deposition of paraffin. Heating the gas slightly by injecting live steam directly into the gas line to the well for short periods at weekly intervals is another method that has successfully eliminated paraffin troubles at some wells, especially those in the Santa Fe Springs oil field."

Compressed air or gas, when introduced into a well, expands and cools, but when this expansion is above the oil sand it has no effect on the temperature of the sand and the oil in the sand. Only where introduced gas or air is expanded directly opposite an oil sand can there be any refrigerating effect that will affect the sand. In this case, accumulations of paraffin may be greater on the sand face.

The application of heat has been found by trial and experiment to be but partially successful under the severe conditions that exist in the Panhandle district. Wells in this district have been kept flowing by the injection of heated gas for a period of 2 months. After this time, they have had to be shut down and cleaned. When this particular oil is kept hot enough to retain its fluidity, a hard scale is formed in the flow lines. This is probably due to the high temperature of the gas required to impart sufficient heat to the oil on account of the great difference between the specific heat of the gas and that of the oil.

The principal difficulty in using heat is that of getting it to the place where it is needed. In a well flowing through tubing, most of the heat will be dissipated out through the casing. If the gas is injected through the tubing, the heat will be given to the oil, but mostly at the top of the well where the greater temperature difference occurs. It has been found practically impossible to get enough heat to the oil throughout the entire length of the flow line; paraffin has been found from 700 to 800 ft. from the derrick floor down to the liquid level in the well.

It has been found advantageous to heat the gas and have some of this heat imparted to the oil in the upper part of the tubing inside the well. This keeps the paraffin from forming in the top section of the tubing and makes it slightly easier to start a scraper in the well. The effect of some heat at the top of the well is to keep the tubing open to its maximum diameter where the expansion of the gas is greatest. When heat is put in the well as described, oil can be delivered to the stock or gage tanks through the flow lines without the addition of more heat. Two principal types of heaters are used in connection with gas-lift work. The steam heater has been more successful, owing to the difficulty on account of breakage in the welds in the direct-flame type. The flame type, however, is more efficient.

Heating of the input gas has been found to help reduce the paraffin troubles and generally to assist the gas-lift operations, for the temperature resulting from the gas expansion upon leaving the well will not be so low as it would were the input not heated, this directly reducing the deposition of the wax along the upper joints of the tubing. Also, the higher temperature resulting from the extra heat units contained in the input agent will reduce the oil viscosity. In one of the Marland Company's wells in the Panhandle field, input gas was heated to 225° F. with good results, the temperature of the return gas at the surface being 115° F.

Reference is made here to the discussion of heating the input gas and the effects thereof which was given under the subject of Temperature Considerations under Operating Procedure for the Air or Gas Drive.

Difference in Use of Air and Gas.—The greatest part of the subject matter appearing under the preceding sections will apply to the use of either compressed air or gas. The actual difference in the use of the two agents is in the quantity necessary, as shown by the following calculation:

As stated before, a greater quantity, in terms of *volume*, of gas is necessary to do the same work, of an equal volume of air.

The work done by the same *weight* of gas in comparison to air in expanding from a pressure of P_1 to a pressure of P_2, isothermally, will be in the ratio of the gas and air constants; that is,

$$\frac{W_a}{W_g} = \frac{R_a}{R_g}$$

where

W stands for the work performed.

For

$$W \text{ (air)} = MR_aT \log_e \frac{P_1}{P_2}$$

and

$$W \text{ (gas)} = MR_gT \log_e \frac{P_1}{P_2}$$

for 1 lb. of each, and the same pressure range during isothermal expansion.

$R_a = 53.34$ and R_g varies according to the gas analysis, but for the present purpose will be taken as 85.7 (for a gas of the following analysis,[1] in percentage: $CH_4 - 76.50$; $C_2H_6 - 21.36$; $N_2 - 0.78$; $CO_2 - 0.74$; and $O_2 - 0.62$). It will be seen that the work done by air will be 53.34/85.7 of the work done by this particular gas, or

$$W_a = 0.622W_g \text{ in terms of equal weights.}$$

To change to terms of *volumes* which are used in oil and gas work, at the temperature T at which the isothermal expansion takes place, assumed to be standard temperature of 60° F. in both cases, and at atmospheric pressure (14.7 lb.):

$$1 \text{ lb. air} = 12.392 \text{ cu. ft.}$$

and

$$1 \text{ lb. (this) gas} = 21.005 \text{ cu. ft.}$$

The work done per cubic foot of air, therefore, equals, in terms of the work done by the gas, $(21.005/12.392) \times 0.662 = 1.054$ or W_a (per cubic foot) $= 1.054W_g$ (per cubic foot). In other words, to use the particular natural gas under consideration, it would require 5.4 per cent more of this gas to do the work of an equal volume of air.

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[1] See MARKS, "Mechanical Engineers' Handbook, 2nd Ed." p. 316.

In general, as stated by one writer:

"Because air works best in a field producing a certain grade of oil, one should not assume that air is always best; and because gas, in one case, increased production over that obtained with air, using the same compressor and the same volume, it does not follow that the same will hold true of another grade of oil, for solubility varies with the gas and with the oil, and slippage also varies with the oil."

"Slippage of gas is greater than slippage of air in some oils, and the opposite holds for other oils. Naturally, though slippage is lower in heavier oils than light, and although the heavier oils set up more friction, efficiency of air lift appears to be greater when pumping heavier oils than light."

"Where gas has a larger solubility factor than air, air may be best, and where air has a larger solubility factor, gas may be best. It is evident in low-boiling point oils, that gas without fractions condensible at moderate pressure is less soluble than in high-boiling point oils; and that wet gas is more soluble in high-boiling point oils, than low. These are but natural laws and when installing gas lift, or air, use of them may assist in solving difficulties."

"Natural gas is used as the lifting medium in the majority of cases, outside the Seminole area, where air is used extensively. Air is cheap and readily available but its use has several serious drawbacks; it lowers the gravity of crude by removing lighter fractions which are not recoverable in gasoline compression plants, and it has a tendency to cause corrosion of tubing and casing, particularly when salt water is present. When air is used, the compressors take air from the atmosphere through a suitable screen or filter, and raise it to the required pressure to flow the wells. The mixture of air and gas produced with the oil is usually allowed to escape into the atmosphere through the release on the separator."

"When gas is used, it is necessary to have a gathering system to recover it. As the majority of gas-lift compressor stations, outside Seminole, are really booster stations, using the residue gas from the absorption type gasoline plant, the gathering system is part of the gasoline plant. Connection is made from the trap or separator to the gasoline plant. The wet gas is brought into the gasoline plant where the gasoline is extracted. The dry gas then goes to the gas-lift compressor stations to be put back through the wells. This process is a continuous cycle and it makes possible the operation of the gas lifts when only a small amount of gas is available in the field. The losses are the volume shrinkage in the gasoline plant, gas used in plant operation, and a small leakage. The gas from the sand is usually sufficient to make up these losses. While the gas from the gas-lift wells will show a slightly lower content than the raw gas from the sand, there is usually more of it available so that gasoline production as a rule does not suffer, either in daily gallonage or in profits."

Turning now to the use of gas in particular, certain principles are applicable regarding the gas that is dissolved in the oil under certain ideal pressure conditions, which would later vaporize or be released in the rising column. Due to the reduced pressures employed, the results secured when this method is employed are not rigidly comparable to the usual air-lift procedure. This, also, probably explains the startling results sometimes obtained in the first or early blind experimental work when conditions now deliberately secured were then only accidentally "happened upon." For example, wells are now being forced to flow oil from as deep as 3,800 to 4,000 ft., with pressure as low as 65 lb. per square inch.

The use of natural gas has many advantages over that of air. It is possible to recover and save the gasoline from the gas that accompanies the oil to the surface. This gasoline would be wasted if air were used as the lifting medium. Also, certain proportions of air and gas form an explosive mixture that cannot be handled safely by compressors. Another advantage that gas has over air is that gas under pressure is more soluble in oil. Gas in solution in oil reduces the viscosity of the oil that is being produced and causes it to flow more readily through the tubing and flow lines.

In the event that gas is used instead of air, the deviation of compressibility from a perfect gas should be taken into account. The analysis of the gas must be obtained before this deviation can be determined by other than laboratory means. The method of determination has been described by Burrell and Robertson in publications of the U. S. Bureau of Mines.

With some of the wells in the Seminole district, another problem was encountered when the air-lift system was installed on the wells showing water. It developed that a certain chemical reaction was assisted by the presence of air with the magnesium and calcium in solution in the water, with the result that the casing and tubing were attacked by corrosion. This hazard was more or less overcome in a few instances by the change from air lift to gas lift to avoid the corrosion of the 6⅝-in. casing through which the wells were flowing, as well as the attack upon the outside of the tubing. In other instances, it has been found profitable and practical to change the method of applying pressure, and to introduce the pressure into the casing to force the flow out of the tubing. In this second method, corrosion was not prevented but a saving in time and money was brought about, in effect, the difference between the cost of 2½-in. tubing and 6⅝-in. casing, aside from the saving in time of pulling and replacing the two strings of pipe.

Operators are now starting to look in the Seminole field for corrosion of tubing and casing. One well has been lost altogether by a string of casing being eaten through, the corrosion hastened, or even caused primarily, by use of the air lift.

An example given by one writer is as follows:

"A well in the Mid-Continent has considerable history in this respect, so it may serve as an example of what may occur elsewhere. This well is the Mid-Continent Petroleum Corporation's No. 3 on state land in 36-29N-1W, Kay County, Okla. It is the original well in Oklahoma to be produced by air lift. It was completed in April, 1917, for initial production of 2,200 bbl., but soon began making much water. Adopting the method used in the Gulf Coast territory, the company installed compressor equipment to reduce the cost of lifting the large volume of water."

"The well now makes from 2,000 to 2,500 bbl. of water each day and about 75 bbl. of oil. The last string of casing is 5$\frac{3}{16}$ in. and tubing is 2 in. Both tubing and this casing string are galvanized, but the corrosive action takes place anyway, although retarded by using the galvanized strings."

"The corrosive action is most pronounced at the fluid level. Four to five joints of tubing and casing must be replaced four times each year. The thing has happened so often that the company knows just when to pull the strings and replace. In fact, they mark the date on the calendar, just as a man marks down when to change the oil in his car."

"It runs true to form every time. The fluid level is about 1,500 ft. from the top of the hole and when that much pipe has been pulled, the next four or five joints will be found to be in bad condition."

"The fact that this last string of casing has no water back of it makes it possible to pull and replace without difficulty. Some companies in Seminole have so cased their wells, but those that have not will be certain to experience corrosion trouble of a kind difficult to handle."

A possible explanation[1] follows:

"If hydrogen sulphide is present, in the presence of water or even moisture such as frequently found in a gas, there is a slow oxidation of sulphur compounds. Under the conditions that may exist in a deep well, where there is some air present, the oxygen from the air tends to combine with hydrogen sulphide."

$$2H_2S + O_2 \rightarrow 2H_2O + 2S.\text{''}$$

"This change indicates the separation of free sulphur, as a fine powder which may go into solution in the oil. However, water and air will aid in the oxidation of this sulphur in a similar manner to that mentioned as taking place when hydrogen sulphide is decomposed."

$$2S + 2H_2O + 3O_2 \rightarrow 2H_2SO_4.\text{''}$$

"Here it is shown that sulphuric acid, H_2SO_4, is formed. There may be a further reaction in which this sulphuric acid may combine with some hydrogen sulphide to form free sulphur, water, and sulphur dioxide. Then the reaction may begin all over again as illustrated."

$$H_2S + H_2SO_4 \rightarrow S + 2H_2O + SO_2.\text{''}$$

"The presence of acid may be confirmed by testing the water that comes to the surface with the oil."

"If the quantity of the water is not very large it may be possible to stop the corrosive action by placing some solid caustic soda in the well. The quantity to be first used would have to be determined by analysis of the water but once neutralization has been accomplished, further additions of caustic soda would not be necessary so long as the water reacted alkaline."

"In some instances where air is used, it is not known how to prevent an underground combustion that actually lowers the gravity of the oil as much as 0.5° Bé. In other cases, there is an actual increase in the gravity, indicating, at least, that there is no combustion comparable to that where there is a decrease in gravity. The return air-gas mixture from the oil wells often shows practically no oxygen but a large percentage of nitrogen and carbon dioxide. This is but one of the several problems to be solved in recovery work. Perhaps ultimately the nitric oxides of the exhaust gases from our gas engines will be neutralized, the inert gas used in place of air."

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[1] FRANCIS, DR. C. K., article on the corrosion of casing when using air lift, *Oil and Gas Jour.*, p. 253, Feb. 10, 1927.

Brundred[1] states in regard to the use of gas or air:

"There are several major advantages in using gas as compared with air as the lifting medium which are worthy of consideration."

"Gas, being lighter than air, under the same pressure will lift a greater volume of oil than the same quantity of air, although this percentage, to be sure, is small."

"Although the horsepower requirement for compressing gas is slightly less than for air, the difference is negligible in so far as it affects the installation of a plant."

"Another and perhaps the most important consideration is that air, in contact with salt or sulphur water, has an extremely destructive action on the tubing in the well, caused by corrosion, whereas little trouble is to be experienced with the average oil-field gas."

"Experience has shown that in the presence of water the atomization of a fluid column by the use of high-velocity gas is less apt to result in cut oil than the use of high-velocity air."

"The use of gas for the gas lift opens a possibility of extracting from the circulated gas such of the lighter hydrocarbons or gasoline forming fractions as may be picked up in the fluid column. This, of course, is impracticable when air is used as the lifting medium. Also, the impracticability of using the return gas as fuel is apparent."

Action in Reference to Water.—Practically all oil fields go to water when the oil is taken out, and quite naturally, for side and bottom water is the vehicle of oil and gas accumulation. When the oil and gas are taken out and pressure is removed from the oil and gas formation, water surely follows, whatever the method used for recovering the oil. If water encroachment occurs in a well pumped with air, then the same well, after delivering an equal quantity of oil and gas in an equal time with any other method of production, whether natural flow or otherwise, would make water.

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[1] Brundred, L. L., Practical Production of Oil by Gas Lift, *Oil Weekly*, Nov. 11, 18, 25, 1927.

Back-pressure control eliminates water troubles to a certain extent, however; wells do not "cone" with water so badly when back pressure is controlled so as to secure production without lowering local sand pressures too greatly.

The following notes on the possible detrimental effects on oil production using gas or air lift were submitted by D. P. Wardwell of the U. S. Geological Survey:

"In oil fields where adverse water conditions prevail, bottom water in particular, but edge water under special circumstances, the use of gas or air lifts as a production method is apt to be harmful. Experience has demonstrated that although a much greater amount of fluid can be produced by this method than by ordinary pumping methods, the increase in amount of fluid is sometimes water. Initially the oil production may be greatly increased, but as the amount of water increases the amount of oil decreases in about inverse proportion. This has been demonstrated in the Kern River field of California, the El Dorado field in Kansas, the Bristow field in Oklahoma, and the Balcones Fault zone fields in Texas."

Brundred[1] published the following comment on this subject:

"In certain sections of the country, bottom water has encroached to a point where the water table is so high that a reduction in the back pressure against the sand will permit of 'coning' up of the water. In such cases the water practically excludes the infiltration of oil, and the well becomes in many instances profitless to operate."

"This coning effect is generally found where the water is immediately under and in direct contact with the oil. Often, wells flowing naturally, without restriction, will permit the water table to rise unnaturally in close proximity to the hole and cause this coning. Swabbing will produce a similar effect. An improperly operated gas lift, if such underground conditions exist, will have the same result."

"In cases just mentioned, the only solution found to date has been 'skimming' properly with the gas lift. Skimming is accomplished by running the tubing to such a point that it will leave sufficient fluid head, between the bottom of the tubing and the top of the water cone, to back pressure the sand properly and thus prevent the water from coming up through the oil."

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[1] Brundred, L. L., Practical Production of Oil by Gas Lift, *Oil Weekly*, Nov. 11, 18, 25, 1927.

"Where the proper back pressure is maintained, the water level will be kept down and the oil will enter over the top of the water surface by lateral travel. This is explained by the fact that water moves only by a direct power application and can be considered inert, whereas oil in the sand is capable of expansion and may be considered as a latent energy. In a great many wells, control of the back pressure is extremely critical. A few pounds increase or decrease in the back pressure will often so raise the percentage of water, and decrease the percentage of oil, as to again make the operation profitless."

"The back pressure is controlled by two factors: First, raising or lowering the tubing will automatically raise or lower the fluid back pressure against the face of the sand. Second, increase or decrease of the volume introduced will respectively lower or raise the pressure on top of the fluid, and such pressure in turn will finally be reflected in the back pressure on the sand."

"It must be said of this method of operation that it is entirely experimental and no tables of results are available."

"The cause appears to be due to hydrostatic back pressure exerted on the oil sand. The back pressure is represented by the difference between the normal hydrostatic level in the well and the fluid drop in operation. For example, if the hydrostatic level is 2,000 ft. (868 lb.) and the fluid drop is 400 ft. (173.6 lb.) the back pressure exerted at the total depth of the well is 694.4 lb. If the rock pressure in the sand is greater than this back pressure, oil will continue to flow toward the well. If only equal to this back pressure, the flow tendency will be toward direction of lesser resistance. If the rock pressure is less than this back pressure, the direction of flow will be reversed and surrounding wells will be benefited in the same manner as in a drive. Usually an oil well producing water will eventually be ruined if the air lift production method is continued."

But, on the other hand, the gas-lift application has attained success in holding back water in the Panhandle field. The problem consists of using the right-sized tubing and of holding it at that point in the well where the weight of the column of fluid plus injected pressure through the tubing on top of the water plane creates a balance that prevents water from coming up through the sand and permits lateral travel of oil through the sand to the well. This balance is a critical one, as experiments have shown that a pound or two difference in pressure will allow water to come in or will hold it back.

The theory, after Bennett and Sclater[1] as to what takes place in the Panhandle wells where water intrudes is as follows:

"As the oil is drained from the sand in widening cone-shaped areas and pressure in the sand diminished, the water level slowly rises, and with swabbing is finally brought up to the point where it shows in the well. This continues until the well is making nothing but water. With gas-lift, an opposite effect is exerted on the water, and with proper balance it is held back."

The following is extracted from a published report and gives an example of the drive effects as a result of the use of a gas-lift installation. After the initial success of the air-lift installation on one lease in a certain field, the Noname Oil Company put in another installation on its A lease, well No. 12. This well was one of the best gusher completions of 1926 and after it had ceased flowing, it produced about 100 bbl. daily on the pump. With the installation of the air lift the production increased to 400 bbl. of oil daily.

This increased production was expected, but the most interesting development was the effect on the wells of the Blank Oil Company lease located directly to the north and called lease B here. Well No. 5 of B lease, ¼ mile north of well No. 12 of the A lease, was completed Sept. 13, 1926, with an initial production of 3,000 bbl. but had decreased to 400 bbl. with considerable water. With the continued operation of the airlift on the A lease well, production from the B lease well increased to 2,800 bbl. daily with very little water—an increase of approximately 700 per cent. In January, 1927, the total production on the B lease had increased about 350 per cent over the previous month's production. The field superintendent of the Blank Oil Company which owned the B lease reported that when the air lift on the A lease well was shut down, for even a few hours, production of the B lease well No. 5 decreased, and if shut down for longer periods, the water percentage began to increase.

Emulsification as the result of the air-lift application is one of the disadvantages. The high velocity in the uptake pipe and the turbulence created through the mixture of gas or air and oil striking the collars, which is an advantage, makes an emulsion if water is present. Some oils emulsify more easily than others; the majority of oil produced at West Columbia was, and is still, emulsified, adding the cost of treatment to the total cost of production. Several millions of barrels remained in storage there several years awaiting treating. But careful attention to details of smooth passages up the well and to securing as low terminal velocities as possible reduces emulsification.

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[1] Bennett, E. O., and K. C. Sclater, Some New Aspects of the Gas Lift, *Petroleum Development and Technology*, p. 133, 1926.

As stated by Brandenthaler:[1]

"The character of emulsion formed is primarily dependent upon the kind of oil, thus more refractory emulsions are formed from asphaltic base oils, less refractory from mixed base oils, and the least refractory from paraffin base oils. However, refractory emulsions are sometimes formed from paraffin or mixed base oils that are difficult to treat by ordinary methods, especially by electrolytic processes. With oils having the same base, those of lighter gravity are less subject to the formation of emulsions and especially of refractory emulsions."

"There are two types of emulsions formed, namely, water-in-oil emulsions and oil-in-water emulsions and of these, the former are the more common; in fact very few examples of oil-in-water emulsions have been noted in the oil fields. The amount of water produced with the oil influences the percentage of emulsion formed. Agitation and velocity of flow play an important part in the forming of emulsions."

"When such a condition presents itself, it is purely a matter for the operator to decide with regard to whether the installation is satisfactory from the standpoint of ultimate profit, considering the cost of having to treat the oil and the loss in gravity due to the emulsification, compared to what can be accomplished with pumping equipment installed, without the emulsified condition but with the pulling account, plus the loss of production during pulling operations."

"A general survey of fields throughout the country indicates that the use of the air-gas lift, irrespective of the type of oil, results in an increase in the percentage of emulsions. This condition is more pronounced in localities where asphaltic base oil is produced. One engineer reports that in a number of wells operated by his company, the gas lift was removed because of the refractory emulsions formed. Greater agitation in the fluid column caused by the introduction of gas or air accounts for the increase in percentage and refractory properties of the emulsion. Possible exceptions to the general rule are instances where the velocity and pressures are controlled in a manner similar to that used by some companies in applying pressure control. That is either by installing the tubing at some distance above the sand and flowing through the tubing or by flowing through the tubing and holding pressure either at the well head or trap."

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[1] Brandenthaler, R. R., Effect of Gas Lift on the Physical Properties of Oil, *Petroleum Development and Technology*, p. 41, 1927.

"As the percentage of water produced increases beyond approximately 15 to 20 per cent, the percentage of emulsion decreases. This condition holds generally with all types of oil and may be accounted for by the fact that the presence of a large quantity of water lessens the possibilites of films of water being formed and remaining around globules of oil."

"In the Seminole area a natural flowing well produced 5,500 bbl. of oil and 6 per cent of water. A 7 per cent emulsion was formed which was easily treated out with a small amount of tret-o-lite. The gas lift was then installed and on the day of installation a 37 per cent water-in-oil emulsion was formed which was more difficult to treat. More tret-o-lite and heat were required to break down the emulsion. On another well in the same area a 4 per cent emulsion was produced prior to installing the gas lift. After the gas lift was installed, the emulsion increased to 64 per cent."

"Another well registered an increase in emulsion from 7 per cent prior to installing the gas lift to 82 per cent after installation. All of these wells produced from between the tubing and casing. In every instance where a large percentage of emulsion was formed the water produced did not exceed 15 to 20 per cent of the wells total daily production."

"In the Tonkawa and Garber fields, and especially in the latter field, large quantities of water are produced with the oil, and a relatively small percentage of emulsion is formed."

D. B. Dow[1] says:

"The use of the gas lift may be advantageous in some fields but at most wells persistent emulsions have been formed when the oil and water are agitated violently by the compressed air as they rise in the well. The persistence of emulsions formed in this way depends upon the character of the oil. In the Gulf Coast field, where the air is used extensively, permanent emulsions that require special treatment are formed. In the West Columbia field, Tex., cut oil produced in certain wells in the east pool breaks down quite rapidly, whereas in the north field the emulsion is most persistent. However, the oil from the east pool is lighter in gravity and is produced at a little higher temperature than that from the north field."

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[1] Dow, D. B., as quoted by R. R. Brandenthaler, *Petroleum Development and Technology*, p. 43, 1927.

The principal factors necessary for the efficient operation of the gas-lift system are high fluid level, gas volume, and absence of water. The jetting action is, of course, agitative; therefore, a jet installation in a well which is producing any noticeable amount of water will result in emulsifying the oil.

An unfavorable feature of the gas lift is its marked tendency to cause increased corrosion. Obviously, where air is used, one may expect an increase in corrosion, because of the introduction of oxygen. Several operations of the Blank Oil Company in Oklahoma, have shown marked increase in corrosion where gas is being introduced. The only explanation so far advanced is that the gas causes increased agitation which mechanically removes the hydrogen from metal surfaces and so prevents polarization.

According to Mills:[1]

"Corrosion in deep wells where there is but little oxygen differs from atmospheric corrosion in that there is not enough oxygen to permit rusting. The corroding surfaces are usually brightly etched, and the products of corrosion are ferrous compounds with a strong affinity for oxygen. Where compressed air is being introduced into the oil sands for repressuring purposes, these conditions are changed. The oxygen of the air acts as depolarizing agent and the products of corrosion also undergo partial oxidation. Consequently the pitting of the equipment inside the wells, especially the pitting of the balls and seats of the valves, is greatly stimulated. Increased corrosion troubles from this cause are being reported in the Mid-Continent fields where compressed air is being forced into the oil sands for oil-recovery purposes."

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[1] MILLS, R. VAN A., Corrosion in Oil and Gas Wells—Its Causes and Prevention, *Petroleum Development and Technology*, p. 591, 1926.

"Certain gases absorbed in water influence corrosion. This is especially true of carbonic acid gas, CO_2, and gaseous sulphur compounds, more especially hydrogen sulphide, H_2S. Hydrogen sulphide is extremely destructive. Oxygen, if present, tends invariably to stimulate corrosion."

Pennington[1] states that:

"Gas has a distinct advantage in fields where the hydrogen sulphide content of oil and gas are high in that corrosion of casing and piping is eliminated almost entirely. It appears, from many tests, that in the case of hydrogen sulphide, when agitated with oxygen of the air, in the presence of iron, active chemical action is set up, and so far as the writer has been able to determine, there is no ferrous metal that will resist the corrosive action of hydrogen sulphide together with oxygen on iron. Having made extended investigation into the corrosion of metals of sulphur compounds, the writer has not yet found, in all the long list of anticorrosive ferrous metals, one that will resist hydrogen sulphide. High chromium steels, wrought iron, pure iron, all yield; gold, silver, copper, aluminum, tin, zinc, lead, all are destroyed, and quickly, and the only answer is that ferrous metals must not be used bare when oil and gas charged with hydrogen sulphide is to be handled with air; that is, this is the only answer so far of which the writer is aware."

"Where there is no gas, the carbon dioxide of combustion, from either smoke stacks or gas engine cylinders, when properly treated to remove the corrosive effect of water of combustion, may be successfully used, although the solubility is higher than either air or gas. Even so, the loss of volume due to portions entering into solution is not so much of a factor as prevents the successful, efficient use of the air lift."

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[1] PENNINGTON, HARRY, Lift Efficiency Depends upon Skill in Design and Operation, *Oil Weekly*, p. 41, Aug. 19, 1927.

CHAPTER XVI

THE AIR OR GAS LIFT (*Continued*)

Effects on the Physical Properties of the Oil.—An important question concerning the gas lift process is one having to do with the quality of the oil produced by such methods as compared to the quality of the oil from the same sand as produced by the ordinary methods of flowing and pumping.

As stated by Brandenthaler:[1]

"Very little specific data are available on the subject and contradictory opinions on the subject exist. Some operators are positive that the gravity of the oil is decreased, while others present data which definitely show that the gravity of the oil is increased. In other localities, some few operators have given careful attention to the effect of the gas lift on the gravity of the oil. In instances where the emulsions formed have given much trouble, the problem has usually been dodged by placing the well on the pump."

"The effects of the gas lift on the physical properties of oil have been classified under the following headings: (1) change in the gravity of oil; (2) changes due to heat; (3) changes due to oxidation when air is used."

"*Change in the Gravity of the Oil.*—Logically, one would be safe in assuming that the introduction of air or gas would result in a decrease in the gravity of the oil being produced. The treated gas contains only such gasoline as has not been removed in the gasoline extraction plant, ordinarily not more than from $\frac{1}{10}$ to $\frac{1}{20}$ gal. per 1,000 cu. ft. of gas. When again recovered after being introduced in a well, the gasoline content has increased to 1 gal. or more per 1,000 cu. ft. As the oil must furnish the additional gasoline, it is reasonable to conclude that the gravity of the oil has been decreased. Tests made in the Mid-Continent have shown that the gravity of the oil has been actually increased when gas is used. With air the increase was only nominal, that is increases of only one or two tenths of a degree were noted. Higher pressures and velocities probably account for the increase in gravity. Further investigation to determine whether the increase is temporary, as I suspect it to be, would be interesting. The weathering of two samples, one obtained from a natural flowing well and another from a well on the gas lift, may result in a change in our ideas. It has even been suggested that the decrease in gravity of the latter sample would be greater because of the removal of certain fractions by the scrubbing action of the dissolved gas."

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[1] Brandenthaler, R. R., Effect of Gas Lift on the Physical Properties of Oil, *Petroleum Development and Technology*, p. 41, 1927.

"A survey of the effect of air or gas on the gravity of the oil indicates that the effect differs to some extent with different types of oil, that is whether asphalt base, mixed base, or paraffin base, the first being affected least and the latter being affected most. However, the gravity of the oil is more of a factor than the type of oil, oils with a higher gravity being subject to greater change."

"Changes in the volume of gas used also affect the gravity of the oil, larger volumes usually resulting in a gravity decrease."

"A series of tests carried on in the Seminole area gave the following results: Over a period of 5 days of natural flow, the gravity of the oil averaged 39.4° A.P.I. The average gravity over a period of 20 days on the gas lift amounted to 40.7° A.P.I. When the gas was replaced by air, the average gravity during a period of 5 days was 39.5° A.P.I. Thus, when air was used there was an apparent increase of 0.1° A.P.I. in the gravity of the oil and an increase of 1.3° A.P.I. with gas over natural flow."

"Another test conducted on seven wells over a period of 10 days resulted in no apparent increase with air and an average increase of 1.04° A.P.I. when gas was introduced. The oil samples were obtained at the trap. This increase in gravity was also noted in the pipe line runs. Some companies report a decrease in gravity of oil in the Seminole area, but I have no definite information to substantiate this statement."

"A series of tests on eight wells were made on another type of oil in another section of the country. The average gravity during natural flow was 28.7° A.P.I. and when on the gas lift it was 28.6° A.P.I., a difference of only 0.1°."

"Four other wells in the same locality were tested, with the following results:

Average gravity during natural flow	25.8° A.P.I.
Average gravity during gas-lift flow	24.8° A.P.I.
Average percentage cut oil during natural flow	0.8 per cent
Average percentage cut oil during gas-lift flow	0.73 per cent
Gasoline content of crude oil during natural flow	21.3 per cent
Gasoline content of crude oil during gas-lift flow	18.3 per cent"

"The gravity of the oil had been decreased 1°. Average percentage of cut oil during natural flow and while on the gas lift was approximately the same. A decrease of 3 per cent in the gasoline content of the crude occurred while the gas lift was used.

"*Changes Due to Heat.*—The utilization of heated gas or air in flowing wells has been used primarily for decreasing the viscosity of low gravity oils and in a number of instances the increase in production has been very noticeable. As practically all gas-lift work is confined to high-gravity oils in the Mid-Continent very little data is available on the subject. From a general observation of field operations in this area and discussion with other engineers, I have concluded that the use of preheated gas has not resulted in a permanent increase in gravity of oil produced or in an increase in oil production in the Seminole area."

"Increasing the temperature of an oil renders it less viscous but at the same time allows for less gas to be dissolved in it at higher temperatures. Thus, with an oil of the character produced in the Seminole area, the gravity of crude would be less at higher temperatures."

"*Changes Due to Oxidation.*—It is possible that the use of air has resulted in some oxidation of the crude oil, an example of which was called to my attention. One well, while flowing naturally, produced 39.6° A.P.I. gravity oil of a greenish color. No water was present. Ten days after the air lift was installed the gravity of the oil had decreased more than 1° A.P.I. and the oil had changed to a slightly yellow color. Information on the subject of oxidation of crude oil when air is used is contradictory. Without more conclusive proof, I would hesitate to state that oxidation actually takes place. It is hoped that further investigation will be carried on to furnish conclusive data on the problem."

"*Conclusions.*—In dealing with the effect of the gas or air lift on the physical properties of oil, the method of application is important. Agitation of the fluid column can be minimized by making the proper type of installation, and with correct operation."

"Flowing between tubing and casing results in greater agitation on account of the tubing collars and further disturbance in flow at the well head between the tubing and casing. The use of larger diameter tubing if necessary to accommodate production rather than to flow between the tubing and casing is recommended. A control of flow velocity will also aid to minimize emulsion difficulties. Either too low or too high a velocity tend to increase the percentage of emulsion. Holding pressure at the trap will often accomplish good results. One objection to holding pressure at the trap is the eventual loss in the higher or more volatile hydrocarbons which are held in solution in the oil and are later lost beyond recovery. While the ordinary types of flow nipples used at the well head tend to increase the percentage of emulsion, the new adjustable type has apparently eliminated some of this difficulty."

From an article by Roy O'Neal[1] on this subject the following extracts are taken:

"This investigation was initiated because of the confusion made by some who have studied the problem. One writer says that the effect of gas lift on oil is uncertain. Another authority when referring to gas lift states, 'When a natural gasoline extraction plant is in operation, a greater volume of gas and often a richer gas is provided than is produced by other methods of oil recovery, and a higher yield of gasoline therefore secured. There is ordinarily little if any reduction in the quality of the crude.' Still another observer in enumerating the advantages of producing oil by gas lift gives 'the recovery of gasoline in excess of the amount recoverable by other means.'"

"The effect on petroleum of agitation with gas or air is described by a well-known physical law, namely, Dalton's law of partial pressures, which may be explained as follows: In gas-lift work each particular hydrocarbon in the gas continues to dissolve in the oil until its partial vapor pressure in the gas is equal to its partial vapor pressure from the oil. Each individual hydrocarbon is absolutely independent of all others. Consequently the character and proportions the different hydrocarbons present in the gas and oil will determine the action."

"All gases diffuse into one another and the process goes on until each gas is uniformly distributed through the entire space.

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[1] O'Neal, Roy, Effect of Gas Lift on Oil and Gas, *Oil and Gas Jour.*, p. 121, Feb. 16, 1928.

If the pressure of each gas be measured separately, it will be found that diffusion continues until the pressure of any given gas is the same in all parts of the space; and further, it will be found that the pressure exerted by each gas is the same as that which the given mass of the gas would have exerted if it alone were occupying the entire space. This pressure is called its 'partial pressure' and the total pressure of the gaseous mixture is the sum of all the partial pressures of the component gases."

"The writer has made several tests on a miniature scale, using oils of various gravities and agitating with residue gases from a compression gasoline plant, the residue from an absorption plant and air. Although the results may not exactly duplicate field conditions, they are comparable with the data of actual field operations which will be submitted subsequently. The rate of agitation, the temperature of the oil, and other factors were maintained practically constant."

"*Experimental Results.*—Attention is called to Tables XXVIII, XXIX, and XXX. With the 28 gravity crude the residue from the compression plant did not change the gasoline content of the oil, but the gravity was raised and the initial boiling point was lowered, which indicates that the light fractions of the gas were absorbed by the oil and that some of the heavy fractions of oil were carried away by the gas. The residue gas from the absorption plant had no effect on the gravity of oil or its initial boiling point, but reduced the gasoline content of the oil only 1 per cent, which is within the limit of error of a laboratory distillation. Agitation with air decreased the gravity of the oil, raised the initial boiling point, and reduced the gasoline content of oil as much as 2 per cent."

"Agitating 38 gravity oil with the residue from the compression plant, the gasoline fraction of the oil was lowered as much as 3.7 per cent and its gravity changed from 59.4 to 58.1° A.P.I., the gravity of the original crude was lowered and the initial boiling point was practically unchanged. The residue gases from the absorption plant gave similar results, although slightly more gasoline was removed from crude. Agitation with air showed that as much as 6.7 per cent of the gasoline was carried away, the gravity of oil being lowered considerably and the gravity of the gasoline fraction was changed from 59.4 to as low as 55.6 when gas-oil ratio was 2,000 per barrel."

Table XXVIII.—Bartlesville Sand Oil, Washington County, Okla.

	Original crude		Residue compression plant						Residue absorption plant						Air					
Gravity I.B.P.	28.5° A.P.I. 162°		*A* 29.3° 108°		*B* 29.5° 105°		*C* 29.4° 109°		*A* 28.5° 152°		*B* 28.5° 148°		*C* 28.4° 162°		*A* 28.3° 215°		*B* 28.1° 220°		*C* 27.9° 228°	
Per cent cut	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.
5	314°	51.0	315°	55.8	316°	56.7	314°	58.0	316°	51.7	318°	52.0	327°	51.5	215°	50.4	220°	49.6	228°	49.4
11.5	392°	42.8																		
11.0	....	....	392°	42.7	392°	42.7	392°	43.2	392°	42.6										
10.5	....	....	....	....	....	....	....	....	....	....	392°	42.9	392°	42.2						
10.0	....	....	....	....	....	....	....	....	....	....	....	....	....	....	392°	43.0	392°	42.8		
9.5	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	392°	42.6

Charcoal tests on gas.
Before circulation.............................. 0.35 gal. per 1,000 0.07 gal. per 1,000
After circulation*............................. 0.34 gal. per 1,000 0.19 gal. per 1,000 0.38 gal. per 1,000
A. Agitation rate 500 cu. ft. per barrel. *B.* Agitation rate 1,000 cu. ft. per barrel. *C.* Agitation rate 2,000 cu. ft. per barrel.
* Rate of circulation, 1,000 cu. ft. per barrel. Temperature 60 to 70° F.

TABLE XXIX.—BARTLESVILLE SAND OIL, OSAGE COUNTY, OKLA.

	Original crude		Residue compression plant						Residue absorption plant						Air					
Gravity I.B.P.	38.7° A.P.I. 84° F.		*A* 38.4° 80		*B* 37.8° 82		*C* 37.3° 84		*A* 37.9° 95		*B* 37.2° 105		*C* 36.8°		*A* 36.8° 140		*B* 36.1° 152		*C* 35.6° 158	
Per cent	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.
5	138	83.8	156	83.0	200	76.5	204	72.7	180	79.7	196	74.5	208	72.1	212	69.2	226	67.2	250	62.7
10	222	68.2	220	68.1	250	64.2	251	64.0	244	62.9	264	62.1	268	61.8	248	63.2	272	60.5	290	58.0
15	260	61.0	256	60.7	288	58.1	304	56.7	284	57.9	286	57.8	292	57.5	292	58.0	302	55.5	324	54.2
20	303	55.8	304	55.4	324	54.0	336	52.3	322	55.0	326	54.8	328	54.6	334	52.7	334	53.0	358	51.0
25	340	51.4	344	51.2	354	51.0	366	50.3	362	51.2	364	51.2	368	51.3	372	49.6	374	49.5	386	47.7
32.7	392	48.4																		
31.5	....	....	392	48.7																
29.5	....	....	....	....	392	47.9														
29.0	....	....	....	....	....	....	392	47.6	392	48.6										
28.7	...	....	....	...	....	....	...	....	...	....	392	47.6	...	....	392	47.0				
28.0	...	....	...	....	...	....	...	....	...	....	...	....	392	47.8						
27.7	...	....	...	....	...	....	...	....	...	....	...	....	...	....	...	....	392	46.8		
26.0	...	....	...	....	...	....	...	....	...	....	...	....	...	....	...	....	...	....	392	
Composite	...	59.4° A.P.I.	...	59.1	...	58.4	...	58.1	...	58.7	...	58.1	...	57.6	...	57.4	...	56.7	...	55.6

Charcoal tests on gas.

	Residue compression plant	Residue absorption plant	Air
Before circulation*	0.36 gal per 1,000	0.07 gal. per 1,000	1.62 gal. per 1,000
After circulation	1.48 gal. per 1,000	1.29 gal. per 1,000	

A. Agitation rate 500 cu. ft. per barrel. *B.* Agitation rate 1,000 cu. ft. per barrel. *C.* Agitation rate 2,000 cu. ft. per barrel.

* Rate of circulation 1.000 cu. ft. per barrel. Temperature, 60 to 70° F.

TABLE XXX.—BARTLESVILLE SAND OIL, CREEK COUNTY, OKLA.

	Original crude		Residue compression plant						Residue absorption plant						Air					
			A		*B*		*C*		*A*		*B*		*C*		*A*		*B.*		*C*	
Gravity	42.6° A.P.I.		41.5°		41.1°		40.8°		41.1°		40.5°		40.0°		40.9°		40.1°		39.1°	
I.B.P.	78° F.		70		80		75		90		100		108		120		135		148	
Per cent	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.	Temp.	Grav.
5	154	85.4	182	80.1	188	76.8	198	76.0	184	79.1	198	73.8	204	68.6	190	75.0	202	69.0	210	65.5
10	202	75.8	218	69.7	230	68.6	232	66.4	212	68.4	230	67.3	238	63.4	214	69.4	232	65.8	244	63.7
15	230	67.7	245	63.5	254	63.2	256	61.7	242	62.7	257	62.0	262	59.6	252	63.3	270	60.4	272	59.5
20	260	61.1	276	58.8	282	59.2	282	58.0	268	59.2	278	59.0	290	57.2	274	58.4	288	56.7	292	56.1
25	297	56.3	304	56.2	308	56.6	314	55.5	292	56.6	302	56.4	318	54.4	296	56.3	316	54.4	325	54.2
30	323	54.5	336	53.2	338	53.0	342	52.2	322	54.2	332	53.9	348	52.4	330	52.7	334	52.1	348	51.2
35	362	51.2	368	50.7	370	50.2	372	50.2	360	51.3	362	51.2	380	49.2	368	50.1	370	49.4	384	48.3
42.5	392	48.2																		
40.5	...	....	392	47.8																
40.0	...	....	...	....	392	47.3	...	....	392											
39.5	...	....	...	....	...	....	...	....	...	48.0										
39.0																				
38.5	...	....	...	....	...	....	392	47.6	...	....	392	48.1	...	....	392	48.2				
38.0	...	....	...	....	...	....	...	....	...	....	...	....	392	47.8						
37.0	...	....	...	....	...	....	...	....	...	....	...	....	...	....	...	....	...	....	392	
Composite	...	61.9° A.P.I.	...	59.6	...	59.0	...	58.6	...	59.8	...	58.4	392	57.1	...	58.9	...	57.1	...	56.2

Charcoal tests on gas.

Before circulation*.......... 0.36 gal. per 1,000 0.07 gal. per 1,000 1.88 gal. per 1,000

After circulation.......... 1.62 gal. per 1,000 1.40 gal. per 1,000

A. Agitation rate 500 cu. ft. per barrel. *B.* Agitation rate 1,000 cu. ft. per barrel. *C.* Agitation rate 2,000 cu. ft. per barrel.

* Circulation rate 1,000 cu. ft. per barrel. Temperature 60 to 70° F.

"With 42 gravity oil and the residue gas from the compression gasoline plant, the gravity of the oil was lowered as much as 2° A.P.I., and gasoline content 4 per cent. The quantity of gasoline removed by the residue from absorption plant was even greater than above and was as high as 4.5 per cent. Air lowered the gravity of oil considerably and changed the gasoline content as much as 5.5 per cent, the gravity of the gasoline being lowered from 61.9 A.P.I. to as low as 56.1 A.P.I."

"The field results of the actual operation of the gas-lift are similar to experimental results. In a well with gas-lift installed by writer the gravity of the oil was 37.1 A.P.I. and had gasoline content of 30 per cent and gravity of 55.6. The oil produced from an offset well in the same sand which was being pumped had a gravity of 38.2 A.P.I., a gasoline content of 32.5 per cent which had a gravity of 58.1."

"One example of a California well in Santa Fe Springs field when pumped had a gravity of 34.8° A.P.I. and a gasoline content in casing-head gas of 0.80 gal. per barrel of oil pumped, but when produced by gas lift had a gravity of 33.6° A.P.I. and the gas contained 1.46 gal. of gasoline per barrel of oil lifted."

"In the Panhandle field gas carrying but a trace of gasoline when injected into a well returned carrying a gasoline content of 1.0 gal. per 1,000 ft. A gas-lift installation using gas in wells in Cat Canyon field raised the gravity of oil from 9 to 13° A.P.I. One company in the Seminole field reports an average increase in gravity of 1.5° A.P.I. when changing from air to gas."

"*Application of Results.*—From these data it may be deduced that the effect of the gas lift on the quality of oil produced is not uncertain, but strictly in accordance with well-known physical laws. The quantity of gasoline removed from the oil, or dissolved in the oil, depends entirely upon the partial vapor pressures of the individual hydrocarbons in oil and gas; that is, a relatively dry gas when used to flow a well producing a high gasoline content oil will remove gasoline from the oil and the quantity removed will depend upon the gasoline content of the gas used. A low gasoline content oil, and consequently a low gravity oil, will absorb some gasoline and probably some permanent gases and will be increased in gravity, the amount depending upon the character of the gas."

"Air will remove the same amount of gasoline from oil as a gas absolutely denuded of gasoline vapors, but since it is almost impossible to find such a denuded gas in any high gravity oil field, it happens that air almost always lowers the gravity and gasoline content of oil considerably more than gas, regardless of whether the gas is from an absorption plant, compression plant, or extraneous sand, provided the air is not being recycled. Even with low gravity oil we could not expect an increase in gravity with air unless perchance there is some oxidation and at ordinary temperatures such chemical reactions are questionable. Considering the resultant corrosion problems, more persistent emulsions produced and explosion hazards, it is usually more economical to use gas instead of air."

"The data show that the residue gas from an absorption gasoline plant removes more gasoline from high-gravity crude than the residue gases from a compression plant which we would anticipate. Mindful of this, it does not seem feasible to construct absorption gasoline plants to treat all the gas from wells operated on gas lift where gas is recycled. If there is an excess in volume of output to input gas and this is of sufficient volume, then this surplus gas could be treated in a plant using the absorption process. The extra investment in treating all the gas in an absorption gasoline plant is made only to accomplish that which could be more profitably attained at the refinery."

"The circulating gas removes some heavy hydrocarbons and only part of the lighter and more volatile ones; in fact, the initial boiling point of the crude, in some cases, was not changed, even though 4 per cent of the gasoline was removed. Cognizant of this, we would not expect evaporation losses of the high gravity crude oil in storage or in handling to be changed considerably by removing some of the gasoline from the oil in the gas lift and gasoline plant operations. In other words, the effect on decreasing the evaporation losses would not be the same as if the same quantity of gasoline was recovered by a skimming distillation in the field."

Attention is invited to the practice of some operators of "lubricating," by hand or automatic control, any extracted gasoline back into the input gas just before it enters the well, be it through the tubing or the casing. As stated above, if this input gas is saturated, it can pick up no more light ends from the crude—therefore, the crude's gravity is maintained.

Efficiency.—It is believed that much of the subject matter which has been published on the efficiencies obtaining in air- and gas-lift practice is an accurate expression of results obtained in the numerous cases reported, but just because each writer uses the term "efficiency," and properly so, to express the ratio of whatever terms or units he has worked with and discussed, it does not mean that the reported results are at all comparable. If the efficiency figures reported by two different investigators are based on different ideas or practices as to the units or phases of the lift practice which are considered as entering into efficiency as reported, the efficiency figures themselves are not comparable. To be comparable, these ratios must be based on the same considerations and factors. The mechanical efficiency of a steam engine may amount to 85 per cent and its thermal efficiency would be high if it were 20 per cent; yet, the uninitiated, if one statement is to the effect that the efficiency of that engine is 85 per cent and another statement is that the efficiency is 20 per cent, may say that it is quite apparent that everything is not as it should be. The point is that, in discussing efficiency, the factors, one of which divided by the other gives a number that represents the efficiency, must be comparable and must be in the same terms and units if two separate tests or practices are to be compared.

In mechanical and scientific applications, efficiency is the ratio of the "output" expressed in any applicable terms or units divided by the "input" expressed in the same terms or units. And since the creation of energy over and above the amount of energy put into the machine or process is impossible, the above expression will always be of a value less than one. In terms of dollars and cents, the ratio of the output to the input must be greater than one if the machine or process is going to pay, but this ratio is not spoken of as efficiency; it comes under the subject of interest and profits.

There are so many different possible efficiencies made up of different factors or phases of the air-lift work that, unless some standard practice for expressing this quantity is agreed upon, argument will continue unless each writer or investigator expresses in plain terms the basis for his statement of efficiency.

As stated by Lucke:[1]

"The ratio of output to input is always an efficiency, so that the efficiency of the power system is the product of all the efficiencies of transformation and of transfer or transmission, and the power loss of the system is the sum of transformation and transmission losses. Some of these efficiencies and losses have received names which are generally accepted and the meaning of which is generally understood by all, but it is equally important to note that others have no names, simply because there are not names enough to go around. In dealing with efficiencies and power losses that have accepted names these names may with reason be used, but in other cases where names are differently understood in different places or where there is no name, accurate description must be relied on. As a matter of fact controversy should be avoided by definition of the quantity considered, whether descriptive names be used or not."

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[1] Lucke, C. E., "Engineering Thermodynamics," p. 47.

Following the idea of the above quotation, the efficiency of an air- or gas-lift installation may be compared to that of a pumping well, on the basis of costs of installation, operation, maintenance and depreciation, and results obtained in terms of barrels of oil produced or of its value in dollars; or the mechanical performance of the two types may be compared, if this should happen to be of any value; or the efficiency of the two methods of operation may be compared on the theoretical ultimate yields to be obtained, which, according to the present information available on the subject, means the conservation of the formational gas or the primary oil producing force, whatever it may be.

In regard to the subject of the efficiency of the air or gas lift itself without comparison with other methods of getting the oil to the flow tanks, one idea is to consider the gas factor or the amount of gas produced per barrel of oil; this idea can be expressed as the total gas issuing from the well per barrel of oil produced, or the amount of gas put in the barrel of oil produced, or the amount of formational gas produced per barrel of oil produced.

Each of the above applications has its value in connection with some particular study or consideration. The energy put into the lift may be compared to the energy represented by the work accomplished, this efficiency being akin to the overall mechanical efficiency of any other power system.

Pierce and Lewis discuss the subject of mechanical efficiency as follows, and this is considered as of the utmost importance since it is the basis for design of a lift installation:

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[1] Pierce, H. R. and J. O. Lewis, Principles of the Air-gas Lift As Applied to Oil Production, *Petroleum Development and Technology*, p. 19, 1927.

"The three main elements consuming energy in the eduction of the liquid are (1) the weight of oil and the distance lifted, (2) the frictional resistance of the upward moving column of oil and gas, and (3) the slippage or dropback of the oil in the upward flowing gas. The first represents the useful work to be done, and, of course, is irreducible, hence efforts to increase mechanical efficiency must be directed to decreasing friction and slippage."

"Friction increases with velocity according to well known laws, but in the air lift it is difficult to determine a friction constant for a well, and as there is an acceleration of velocity from the bottom to the top of the flow pipe the computation of total friction is an involved problem. The problem of friction is thus to keep down velocity."

"Analyses of air-lift data by graphic and other means indicate that while friction increases with velocity, the slippage decreases with velocity, thus where slippage predominates, friction tends to be the minor quanity and *vice versa*, so that when we reduce one the other increases and our final problem is in keeping these two factors balanced so that their combined loss is a minimum. The fundamental laws governing the volume of a gas at different pressures, and the work available in gas due to its state, are very simple, but the methods of directing these laws, or rather, the arrangement of our equipment so that we may benefit most, is our complicated problem. These problems are:

A. 1. The complicated laws governing the variation of friction of flowing gases and fluids. Although similar, the friction of flowing water or oil, and gases, are not identical.

2. By the fact that the law governing the flow of either, changes at some critical velocity.

3. By the fact that the relative quantity of gas and oil or water, or all three are variable in any flowing column; that is, the relation of quantity of gas and oil or gas, oil and water in the rising column varies from top to bottom of the eductor tube.

4. The change of the friction laws of the flowing constituents at some specific velocity.

5. The variation of volume and pressure of the gas, or pistoning, or lightening medium of the column.

B. The fact that slippage varies with nature of gas and fluid to be lifted, and with the changes in the quantity relation of gas and fluid, and with the state of the gas.

C. Due to the fact that oil wells are not drilled and cased especially for gas lifts, and the rock pressures or submergences are not chosen for efficiency alone, but chiefly to allow the greatest quantity of oil to come into the well; therefore, and as a consequence, producing oil by gas lift is not merely a gas-lift problem, but is inseparable and a really minor part of the oil production problem, and as a consequence becomes more complicated and involved, due to the limits imposed upon its operation."

"As a summation of *A*, *B*, and *C*, we wish to say that the gas lift in its simplest form has never been thoroughly analyzed or reduced to mathematical calculation. Therefore, we do not have hopes for a complete or definite mathematical analysis of all its adaptions to oil production, but we do believe that by the study of all the obtainable factors in any one pool or well, oil can be produced in some instances more efficiently and cheaper by the air-lift method than by other methods, but we also believe that many of the claims for gas lift are a little rosy, and that in many cases more efficiency could be had by a careful analysis at regular periods on the various wells on a lease. Although, as we have pointed out before, we do not believe any fixed mathematical analysis can be devised whereby all conditions can be reduced to a common denominator, we do believe that, with the combination of experience in various fields on which an intelligent, consistent analysis has been made, much can be done to eliminate the mistakes so common in the application of air lift to oil production in new or untried wells or pools."

The above considerations enter into the design or adaptation of the available mechanical equipment to the well with the ultimate view of producing the greatest possible volume of oil with the least expenditure of energy or with the lowest operating cost. In regard to the efficiency of the lift when the ultimate recovery is considered, Bennett[1] states:

"The gas lift has been used primarily as a means of increasing the output of wells; and but little thought has been given to the efficiency of well flow with regard to ultimate recovery. Most gas- or air-lift installations have been put in with the view of getting maximum production and maximum mechanical efficiency in the flow line. But little regard has been given to that part of the well below the flow line. When compared to the efficiency of the well the mechanical efficiency of the flow line is of secondary importance. To strive for mechanical efficiency in the flow line only will generally cause an economic loss in production."

"It is true that with a high mechanical efficiency in the flow line a smaller amount of gas is required to raise a barrel of oil than when low efficiency exists. If the amount of gas coming from the formation is ignored, the total production efficiency of the well may be very low even with the very best mechanical efficiency in the flow line. The result of this condition is that while a fair rate of production may exist the well's ultimate recovery will be decreased. Efficient operators equip their wells with meters and gages on the input side. There are, however, very few who measure the discharge gas from the well. The difference between the output and the input gas is the amount taken from the formation. It is called the 'natural-gas factor.' The natural-gas factor is the best criterion of the well's condition and should be given the most consideration at all times. A careful study of natural-gas factor decline will give very valuable information regarding the ultimate recovery of a well."

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[1] BENNETT, E. O., Effect of the Gas Lift on the Gas Factor and Ultimate Production, *Petroleum Development and Technology*, p. 159, 1927.

Another writer states the above idea as follows:

"Much has been said of late about the mechanical inefficiency of gas lift, and from a comparison of input to output on a power basis the statements may be correct but inasmuch as production efficiency is not a ratio of power applied to work done, but rather of dollar returns per dollar invested the efficiency of gas lift is high compared to pumping, and, in most cases, natural flow. With due credit for reduction in direct lifting cost, reduction in gas-oil ratio, and consequent increase in ultimate yield, reduction of mechanical hazards and lost time, and the placing of wells under the direct control of the operator, the relative efficiency of gas lift over pumping in Southern California may be expressed by at least 3:1 under average conditions."

It is believed that the term "production efficiency," as here defined, is the efficiency which should be considered, since the purpose of the application is to produce oil and not energy. In line with this expressed idea it must be kept in mind, in the discussion of the mechanical efficiency obtained, that, when pumping water, a substance of comparatively low commercial value per barrel, the operating cost and, therefore, the mechanical efficiency is of comparatively great importance, but on the other hand where oil, which is of much greater value per barrel, is the material being handled, the main purpose is to secure the oil regardless of that part of the operating cost as influenced by the mechanical efficiency of the lifting process. In other words, while the best design as based on mechanical consideration should be employed, the production efficiency in the case of the air- or gas-lift installation working with oil should not be sacrificed in order to obtain a high mechanical efficiency.

The gas-oil ratio, or number of cubic feet of gas that accompanies 1 bbl. of oil from the sand, is only the roughest kind of an indicator so far as lifting efficiency is concerned, since it does not take into account the height to which the oil is to be raised, nor the foot-pounds of work stored in 1 cu. ft. of gas. For example, a gas-oil ratio of 100 cu. ft. per barrel of oil may, theoretically, apply to a lift of 1,200 ft. with gas at 100 lb. pressure, or to a lift of 2,500 ft. with gas at 850 lb. pressure. Again, for a lift of 1,200 ft. and 100 lb. pressure, 1 bbl. would be raised at efficiency of 100 per cent where the gas-oil ratio is 100; while for 1,200-ft. lift at 850 lb. pressure, a gas-oil ratio of 49 cu. ft. per barrel would be required at 100 per cent efficiency.

Brundred[1] discusses the matter of the "net" gas factor as follows:

"By 'net' gas to oil ratio is meant the ratio of the natural gas produced from the oil sand to each barrel of oil produced and must be distinguished from the 'circulated' gas to oil ratio, which means the ratio of the number of cubic feet of gas introduced at the surface to raise a barrel of oil from a given depth. Invariably it has been noted that, in a properly operated gas lift, there has been automatically a saving experienced in the net gas to oil ratio. A few examples taken from actual experience in the different fields show as follows:

Table XXXI

Natural production, flowing or pumping		Net gas-oil ratio	Production from same well by gas lift	Net gas-oil ratio, well gas lift	Gas conserved, percentage
Well:					
A	1,710	2,100	1,725	873	58
B	945	3,200	1,120	1,720	46½
C	440	1,718	622	515	70
D	405	1,850	408	690	62½
E	178	1,108	322	660	40½
F	130	1,710	781	505	70
G	65	1,750	80	448	75
H	20	3,760	21	1,100	70½

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[1] Brundred, L. L., Practical Production of Oil by Gas Lift, *Oil Weekly*, Nov. 11, 18, 25, 1927.

"Based solely on physical experience in the field, it has been determined that the ratio of total gas introduced into the well necessary to raise a barrel of oil increases as the total production of the well decreases. This is primarily due to the fact that the rock pressure is considerably less in an old well than in a new one and will, therefore, not raise the fluid to the same height as it would when the well was flush. Also, due to the liberation of the lighter fractions the oil contains less absorbed gas in solution rendering it necessary to introduce circulated gas in greater quantity."

"Based upon experience in one field of an average tubing depth of 4,000 ft. the following table was prepared. It must be understood that it will serve as an indication only of the general change in circulated gas to oil ratios as production of the wells in that field declined."

Table XXXII.—Change in Circulated Gas to Oil Ratio

Production, barrels	Circulated gas to oil ratio, cubic feet per barrel	Total circulated gas
4,000	250	1,000,000
2,000	400	800,000
1,000	700	700,000
700	900	630,000
500	1,000	500,000
300	1,300	390,000
150	1,600	240,000
100	1,800	180,000
50	2,400	120,000
25	3,000	75,000
10	5,000	50,000

"It must be noted above that although the circulated gas to oil ratio is gradually mounting as the total production of the well decreases, the total volume of circulated gas is decreasing."

"Naturally the figures given in the above table would change very materially where there is an excessive amount of natural gas being produced from the sand and, thereby, assisting in lifting the oil from the bottom of the hole."

"The circulated gas to oil ratio is important in that the lifting cost per barrel is based on this ratio. However, a table of gas to oil ratios based upon the total gas actually received from the well is of the utmost importance in that a determination of the amount of gas liberated from the producing formation can thus be made."

As stated by Shaw,[1] the gas-oil ratio takes into account only the gas associated with the oil; the efficiency factor refers to the lifting efficiency obtained, whether it be in a well flowing naturally or whether it be one flowed by means of the air or gas lift.

"Where compressed air or gas is admitted to the well the term 'gas-lift factor' might be employed to distinguish between the gas associated with the oil and the total gas employed in lifting the oil. In a flowing well the gas-oil ratio and the gas-lift factor would, of course, be identical. The efficiency factor is obtained by dividing the foot-pounds of work performed in lifting a unit volume of fluid to a given height by the foot-pounds of work that would be performed by a unit volume of gas in expanding from the pressure under which it is compressed to the lower pressure at which the fluid is discharged. In the case of a well flowing naturally the gas-oil ratio becomes one of the important factors on which the efficiency is based."

The term "efficiency" includes the duty of formation gas produced with the oil as well as the duty of compressed gas mixed with the formation gas, for the two quantities are utilized together in doing the same work, and, while the solubility factors of formation gas and compressed gas differ, still, both do work, each in the ratio of its percentage part of the total free gas being produced with the oil.

Pierce and Lewis[2] discuss the inadequacy of the gas factor when used alone to indicate or measure the efficiency as follows:

"In order to point out the fallacy of basing oil recovery efficiency on gas-oil ratios only, we will work out two specific problesm, which problems represent approximately the conditions existing in two pools with which we are familiar, taking one well from each pool, which will hereinafter be designated as A and B."

"Well A is 4,000 ft. deep and has 1,200 lb. absolute rock pressure, and is flowing with 200 lb. absolute pressure at the sand face and 15 lb. absolute pressure at the well head. It is producing 3,000 bbl. of oil per day with 1,500,000 cu. ft. of gas of a gravity of 1."

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[1] Shaw, S. F., Efficiency in Relation to Gas-oil Ratios in Flowing Wells, *Oil Weekly*, p. 24, Jan. 28, 1927.

[2] Pierce, H. R., and J. O. Lewis, Principles of the Air-gas Lift As Applied to Oil Production, *Petroleum Development and Technology*, p. 19, 1927.

"Well B is 2,000 ft. deep and has 325 lb. absolute rock pressure in the sand, and is flowing with 122 lb. absolute pressure at the sand face and 33 lb. absolute back pressure at the well head. It is producing 600 bbl. of oil with 600,000 cu. ft. of gas per day of 1 gravity."

"In case A, there is required 500 ft. of gas to produce a barrel of oil from the sand, and in case B, there is required 1,000 ft. of gas to produce a barrel of oil from the sand."

"Assuming adiabatic work by the gas, the number of foot-pounds required to expel the oil from the sand in case A is 5,560,000,000 and in case B is 1,110,000,000. The foot-pounds per barrel in case A is 1,855,000 and in case B is 1,855,000."

"The practical use of such efficiencies is to estimate the compressor volumetric requirements: for instance, the actual energy used to expel 1 bbl. of oil from the sand is the same in A as it is in B, even though twice the number of cubic feet of gas per barrel of oil was used in B."

"Still assuming adiabatic work of the gas, the foot-pounds of work in the gas in expanding from the sand to the surface in case A is 2,680,000 and case B is 2,680,000. But this quantity of gas or energy was not sufficient to keep the wells flowing steadily under the above conditions, and it was in each case necessary to supply additional air."

"In case A, there was supplied an additional 1,500,000 ft. per day, making a total of 3,000,000 ft. per day."

"In case B, there was supplied an additional 600,000 cu. ft. of gas per day, making a total of 1,200,000 cu. ft. per day."

"Therefore, the foot-pounds of work used in lifting the oil from case A is 16,000,000,000 and in case B is 3,200,000,000. The foot-pounds per barrel in case A is 5,360,000 and in case B is 5,360,000. The efficiency of lifting the oil only, by the gas assuming isothermal expansion, the specific gravity of the oil as 0.86, in case A is 22.3 per cent and in case B is 11.15 per cent."

The theoretical requirements having been found to be 200 cu. ft. for certain conditions and with a lift efficiency of 10 per cent which may be predicated upon past experience, the probable capacity requirements will then be, $200 \div 0.10 = 2,000$ cu. ft. per bbl.

To give an idea of the efficiencies obtained by some gas-lift installations, Table XXXIII as published by Shaw is given here.

TABLE XXXIII

Field	Gas-oil ratio	Gas added	Gas-lift factor	Depth, feet	Pressure, pounds, square inch	Specific gravity	Percentage efficiency
California.........	1,059	630	1,689	4,231	120	0.865	11.9
California.........	227	1,783	2,000	3,880	155	0.882	9.3
California.........	1,577	2,143	3,720	4,182	130	0.876	6.5
Dominguez, Calif..	1,100	1,200	2,300	3,610	260	0.876	7.2
Huntington Beach.	928	2,222	3,150	4,519	280	0.9	6.0
Santa Fe Springs..	611	406	1,077	3,700	195	0.87	14.8
Seminole, Okla....	490	310	800	3,880	500	0.82	12.6
Seminole, Okla....	540	606	1,146	3,990	136	0.82	18.6
Tonkawa, Okla....	667	222	889	4,100	250	0.82	18.0
Tonkawa, Okla....	377	445	822	4,100	250	0.82	21.4

Pennington[1] states:

"When referring to efficiency, let us examine not efficiency itself, but the effect of efficiency. Plant costs for compressor stations are high, per well, particularly in deep wells, and the writer estimates that ten millions of dollars would scarcely cover the cost of stations erected in the Mid-Continent, Panhandle, and California within the past 18 months."

"Yet, in no case could the writer find that a reasonable efficiency was being obtained. With an efficiency of 10 per cent using air, and a cost of compressor plant total investment in air plant during the past year, an increase of 5 per cent in efficiency means that 33⅓ per cent of plant cost would be eliminated, and with an increase of 10 per cent, plant costs are halved and five millions of capital are then made to do the work of ten millions. But with gas from the formation doing work and the remainder of power furnished from compressors, increasing the duty of formation gas, as well as that of compressed gas, has quite another bearing on plant investment, as will be noted from an example cited further along in this paper."

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[1] PENNINGTON, HARRY, Lift Efficiency Depends upon Skill in Design and Operation, *Oil Weekly*, p. 41, Aug. 19, 1927.

Again referring to Shaw:[1]

"The efficiency figure depends on the design of the air-lift installation and on the manner in which it is operated. Losses in efficiency in an air lift occur as follows:

1. Entrance losses at lower end, or footpiece.
2. Slippage losses, principally in the lower section of the pipe, or eductor.
3. Friction losses, principally in the upper section of the flow pipe.
4. Discharge losses, at the upper end of the flow pipe, or eductor."

"The designs of the footpiece, of the flow pipe or eductor, and on the discharge arrangements or headpiece, control the losses at those points. These losses will be small or great depending on whether or not the designs are such as to meet the existing conditions in the most efficient manner."

"Efficiencies are dependent in varying degree upon designs of footpiece, flow tubing, and discharge arrangements, and these are in turn dependent upon conditions existing at the well. Improper sizes of pipes, right angle turns, and horizontal flows all tend to reduce the efficiency. In very shallow wells where fairly high percentage of submergence is available, as high as 70 per cent efficiency is possible to obtain, while in wells 4,000 ft. in depth with submergence pressure of 200 lb. per square inch, 30 per cent efficiency would be very high. In general, it may be said that efficiencies as low as one-half the percentage of submergence should never be accepted, while efficiences as high as the percentage of submergence indicate very good work."

Pierce and Lewis published the following additional statements on the subject:

"In addition to the factors discussed on the efficiency of the air lift, there are many others, of which space will not permit more than mention. These include sizes of air and flow pipe, designs of footpieces, air ejection, the relative merits of annular and tubular flowing, the solubilities of air and gas and their relative advantages, the use of booster holes, intermittent air lifts, and many others. As to these factors but a few points can be made."

"The air pipe can always be smaller than the flow pipe, yet there can be a surprising loss in pressure in deep wells, in small air pipes which should be guarded against. To handle much fluid the flow pipe should be comparatively large, but if there is little fluid the slippage losses will be excessive and in fact the air lift may be inoperative. Where the fluid becomes small in amount tapered tubing should be used. Whether to use the central pipe as the air or flow pipe is usually a practical consideration as to the quantity of fluid to be flowed, corrosion problems, and so on. Footpieces have been elaborately investigated and found to have but small influence on efficiency. The values of different designs of the air injectors have also been exaggerated. Too little reliable and comparative data have come to the writer's attention as to the relative merits of gas and air to warrant the expression of any opinions. The intermittent air lifts involve more practical differences than theoretical differences."

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[1] Shaw, S. F., Principles of the Air and Gas Lift, *Oil and Gas Jour.*, p. 40, June 16, 1927.

The efficiency of the gas lift depends to an important degree upon the extent to which the occluded gas bubbles are able to rise through the education tube without corresponding movement of the oil in which they are immersed. This gas "slippage," as it is termed, depends upon a number of different factors, the more important of which are the viscosity and surface tension of the oil, the relative columns of gas and oil, and the diameter of the eduction tube.

When the subject of efficiency of a lift installation is considered in its final aspect, each and every factor entering in the make up of the lift installation and its operation has some effect on the final figure. Pennington listed these factors as follows:

"Quantity of fluid daily.
Weight of fluid.
Static head.
Working head.
Depression factor.
Size of well casing.
Submergence.
Working pressure.
Size of eduction pipe, or flow line.
Size of air or gas inlet line.
Friction of air-oil or gas-oil mixture.
Friction of air in down pipe, or gas.
Inlet velocity at bottom of flow line.
Outlet velocity, at top of flow line.
Viscosity of fluid-gas or fluid-air mixture.
Gas content of fluid, or solubility factor.
Quantity of formation gas produced."

In working out, according to Shaw,[1] the efficiency of an air-lift installation:

"It is necessary to measure the lift, submergence, quantity of fluid being pumped per minute, and quantity of air being used. From these data the quantity of air required per gallon, or barrel, of fluid lifted can be calculated and the pumping efficiency obtained. For instance, take as an example, an oil well in California where the lift is 470 ft. and the submergence is 330 ft. The total number of cubic feet of air is 140. This divided by 93, the gallons being pumped, gives 1.5 cu. ft. as the quantity of air being consumed per gallon of fluid. By referring to Table XXII and by interpolating, it will be found that with a lift of 470 ft. and a submergence of 330 ft., the air required to raise 1 gal. of water at 100 per cent efficiency is 0.788 cu. ft. This divided by 1.5 gives 52.5 per cent as the pumping efficiency being obtained."

"Now taking an example from late practice, as cited in an article.[2] Well G, with a casing pressure of 480 lb., has an average daily production of 2,218 bbl. with an expenditure of 633 cu. ft. of gas per barrel of oil raised. The depth to which the tubing extends in the well is not stated: but if the depth of the well be 4,200 ft. and the tubing 622 ft. above the bottom of the well, the length of the tubing would be 3,578 ft. The casing pressure is 480 lb., corresponding to a submergence of 1,106 ft. The lift would then be 3,578 ft. less 1,106 ft., or 2,472 ft. By referring to the table, it will be found that under those conditions the quantity of air required to lift 1 gal. of fluid—assuming the specific gravity and viscosity of the fluid to be that of water—is 2,781 cu. ft., and to lift 1 bbl. would be 116.8 cu. ft. Dividing 116.8 by 633, the pumping efficiency under those conditions is found to be 18.4 per cent."

When a well, either flowing naturally or by gas lift is put under pressure control, the production rate for best results is reduced to 60 to 80 per cent of the open flow of the well. After the differential in the formation is decreased, due to the pressure imposed, the decline rate will be far less than that which will normally occur under open-flow conditions. The amount of oil not produced after first applying back pressure, on account of

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[1] SHAW, S. F., Air Lifts Employed in Oil Wells, *Oil Field Eng.*, p. 58, November, 1926.

[2] SWIGART, T. E., *Oil Weekly*, Feb. 27, 1926.

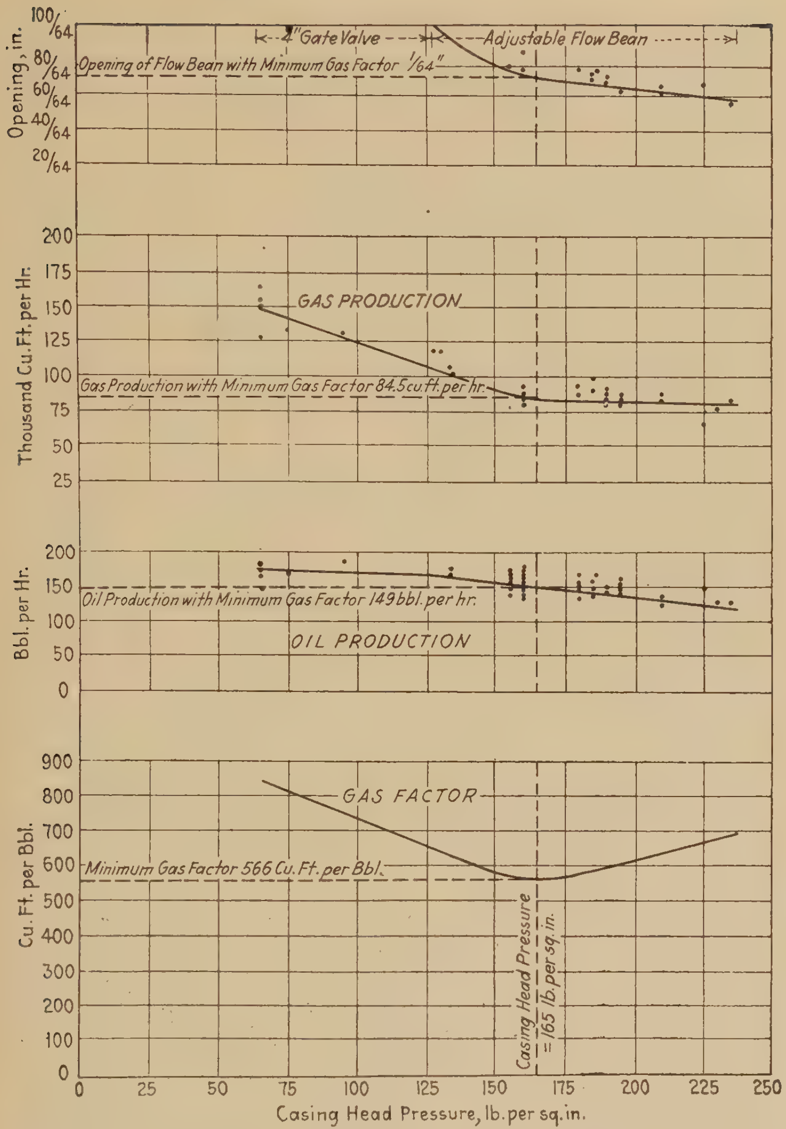

FIG. 107.—Data obtained by actual test on a natural flowing well. (*Bennett.*)

the decreased rate, is soon regained by the flat decline existing after back pressure is applied. As discussed by Bennett:[1]

"Figure 107 shows data obtained by actual test on a natural flowing well.

"An analysis of the data of Fig. 107 shows that as the flow-bean opening is reduced the production rate is also reduced. The rate of decrease in production is about equal to the reduction in area of the opening through the flow bean. It can also be seen that as the flow-bean size is decreased the amount of gas produced is very materially lessened up to a certain point. At this point the flow differential is such that the formation is practically resaturated as previously discussed. After this point is reached further reduction of bean size has but little effect on the amount of gas escaping with the oil."

"The lower curve of Fig. 107 is calculated from the gas and oil production curves. It clearly shows that there is a pressure at which the well can be operated to give maximum efficiency regarding the gas factor. This point may not give the best mechanical efficiency, but it is the one which will allow the well to produce the greatest ultimate amount and the point at which the well should be operated regardless of flow-line efficiency."

"As the formation gradually becomes depleted the pressure conditions change. This effect causes the low point of the gas factor curve to move to the left. Not enough data have been obtained to date to indicate the relationship between the working pressure and the rock pressure for the point of minimum gas factor. Work done on control and operation of gas wells shows this relationship to exist."

"Figure 108 shows the production and gas-decline curves of a gas-lift well. The data for these curves were started the day the well was placed on the gas lift. This well would not flow naturally when drilled in but was swabbed through the 8¼-in. casing at the rate of 1,700 bbl. per day. Swabbing the well caused the collapse of the bull wheel shaft and other difficulties accompanying this method of production which made it uneconomical. The lowest possible back pressure was imposed on the well while it was being swabbed."

"After the well was placed on the gas lift it started to decline regularly at the rate of about 6.5 bbl. per day, with an increasing natural gas factor and a declining working pressure. Although the decline on the gas lift was far less than that under natural flowing conditions it was considered too great. The estimated

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[1] Bennett, F. O., Effect of the Gas Lift on the Gas Factor and Ultimate Production, *Petroleum Development and Technology*, p. 159, 1927.

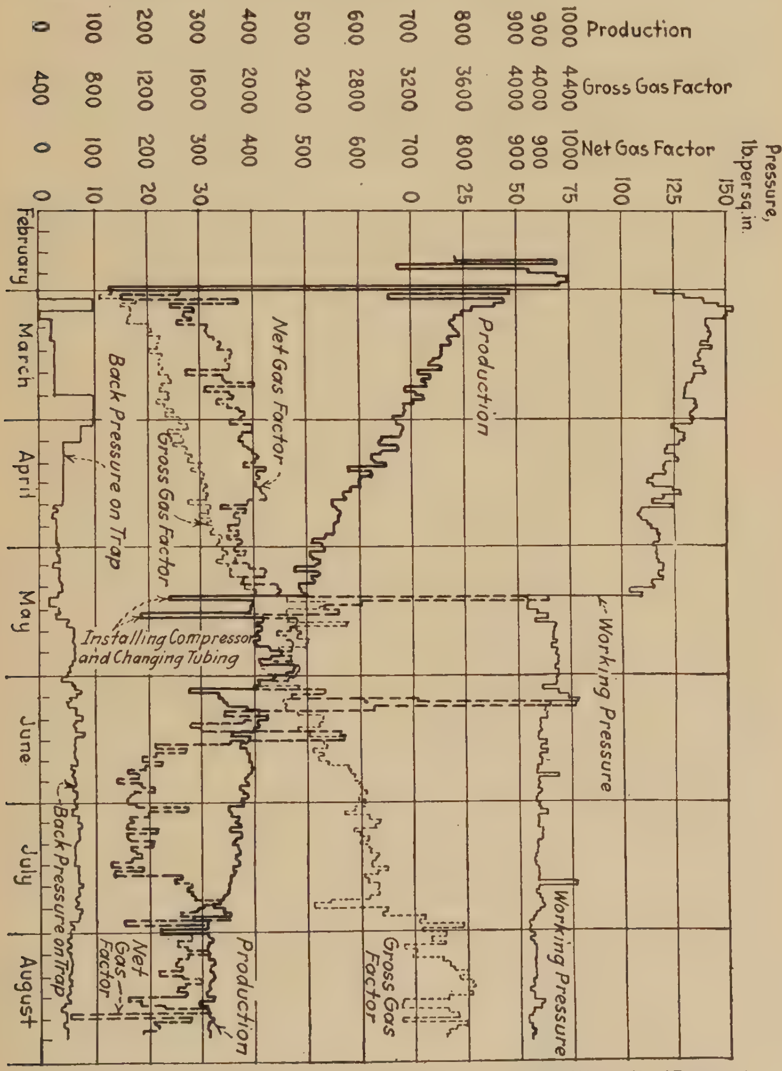

FIG. 108.—Production and gas-decline curves of a gas-lift well. (*Bennett.*)

natural flow decline curve is shown below the gas-lift curve. After the well had produced for about 2½ months the tubing pattern was changed which permitted a reduction in working pressure from 124 to 60 lb. This large reduction in pressure was made possible by circulating more gas per barrel than had been previously used. This can be seen by studying the gross gas-factor curve. At the same time the pressure was reduced in the flow line the back pressure on the formation was reduced."

"Based on mechanical efficiency in the flow line as in general practice the efficiency of this well looks exceedingly poor, the output gas factor being about 3,500 cu. ft. per barrel. In making the changes the net or natural gas factor was decreased from 500 to 175 cu. ft. per barrel. In other words, the change permitted the well to produce with about one-third as much energy as had previously been used from the formation. It will be noted that while the production rate dropped after the change was made, its rate of decline became much less and in 12 days after the change was made the curve crossed the former decline curve and remained practically constant. Extreme irregularities in the curves are due to engine and compressor troubles."

"The only expense involved in handling a well in this manner as compared to getting maximum efficiency from the flow line is the cost of compressing the gas circulated. When the production under 'flow-line efficiency' and 'ultimate efficiency' is compared it can be seen that this added expense is very small compared to the increased returns from production."

"In this particular well there was no increased cost on account of increased amount of gas circulated. When the tubing or flow line was changed to permit the larger volume the working pressures changed to the point where single instead of two-stage compression could be used. This permitted handling a larger volume with the same horsepower requirements, the cost being proportional to the horsepower used. In designing a gas-lift installation it is advisable to choose a type of machinery that can readily be changed from two stage to single stage when required."

"By maintaining some back pressure on the well head the efficiency of the whole cycle is increased. Maintaining 15 lb. on the compressor intake doubles its capacity. The increased capacity permits lifting the oil with higher back pressure than could otherwise be used and with the well head back pressure permits the total differential pressure from the formation to the trap to be controlled. The working differential in the well referred to is but 38 lb. from the sand to the trap. The depth of the well is 2,500 ft. and the size of the flow line is 5$\frac{3}{16}$ in. This is considerably larger than the flow lines used in general practice for wells producing but 300 bbl. per day."

"By proper handling of the gas in a gas-lift cycle the gravity of the oil may be raised and the amount lost by outage vapors decreased. On the well referred to the discharge from the trap is recycled through the compressor. The wet vapors or lighter hydrocarbons that were formerly escaping from the trap amounted to 5 per cent of the total production; when returned through the closed system they increased the production 20 bbl. and the gravity 3¾ deg."

Pumping Oil with Compressed Air or Gas.—There are two ways of handling the gas or air; the first is to introduce it into the top of the tubing and use the space between the tubing and the casing as an outlet for the fluid; the other is to introduce the air or gas into the space between the tubing and the casing and use the tubing for an outlet (see Figs. 109 and 110).

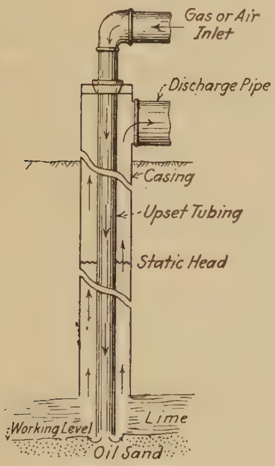
Gas or Air Inlet
Discharge Pipe
Casing
Upset Tubing
Static Head
Working Level
Lime
Oil Sand

FIG. 109.

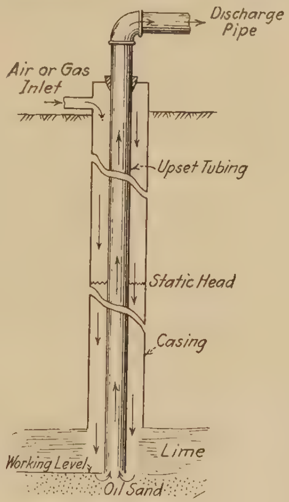
Discharge Pipe
Air or Gas Inlet
Upset Tubing
Static Head
Casing
Working Level
Lime
Oil Sand

FIG. 110.

FIG. 109.—Air-gas lift. In this installation, the air or gas is introduced into the tubing, and the oil is discharged in the space between the tubing and the casing. (*Shaw.*)

FIG. 110.—In this installation, the air or gas is introduced between the tubing and the casing, and the oil is discharged through the tubing. (*Shaw.*)

One writer describes the early Gulf Coast installation practices as follows:

"One of the most economical strings for producing with air in the early days of air methods in the Gulf Coast was an arrangement of a 2-in. flow line suspended in the 6⅝-in. casing with a 1¼-in. air line running along side of it and jetting into it near the bottom. This size line was less costly and carried more pressure than the larger air lines. Below the point of connection of the 1¼-in. and the 2-in. a nipple was placed on the flow line to regulate the flow and well pressure to the point of making it safe against sanding. Below the nipple was a check valve, which permitted the intake of fluid from the hole but kept fluid from going back into the bottom of the well in case of higher air pressure than rock pressure. In many cases a 1-in. line was used in place of the 1¼-in. In the event of trouble with the system it was only a matter of pulling this combination of small lines, which was suspended loose in the well."

Swarts[1] tells of the early Seminole installations:

"Six and five-eighth inch casing was commonly used as a production string with a five and three-sixteenths inch liner set on top of the oil sand. Two and two and one-half inch upset tubing was used for introducing the gas and air. The tubing was lowered within a few hundred feet of the top of the oil sand and sufficient air or gas was introduced at the required pressure to cause the well to flow. In a few cases fluid levels were measured and the desired depth for the tubing was calculated from these measurements. Tubing depths were frequently changed to increase daily production."

"When production had declined to such an extent that the annular cross-sectional area between the tubing and casing was more than sufficient to accommodate the quantity of production, the flow was reversed in order to reduce the excessive amount of air or gas which was required when flowing through the casing. Some of these changes were successful in that they maintained or nearly maintained the previous rate of production and at the same time reduced the compressor requirements. More often, however, the results were unfavorable from the viewpoint of the operator, as the decrease in production more than offset the advantage gained by the reduction of the air or gas requirements. One or two companies used tapered tubing ranging from 2 in. at the bottom to 5³⁄₁₆ in. at the top. In most cases the use of tapered tubing was successful, resulting in lower working pressures, reducing the quantity of gas used and maintaining about the same rate of production. In one well production was increased about 50 per cent."

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[1] Swarts, C. R., Mechanical Installations for Gas-air Lifts in the Seminole Area, *Petroleum Development and Technology*, p. 78, 1927.

Brundred[1] divided wells on a basis of production possibilities and his notes on each class are as follows:

"*Large Wells:* 1,000 *to* 7,000 *Bbl.*—In general, wells capable of making this much fluid will flow naturally. A study of the rock pressure existing in fields where such large flush wells are encountered will show that the pressure per square inch in the sand is hardly sufficient to lift a solid unbroken column of oil this entire distance without assistance."

"When the well is first drilled in, a sharp reduction in pressure takes place in the immediate vicinity of the hole itself. This causes a vaporization of the gasses in solution in the oil to such an extent that they aerate or lighten the column and cause the well to flow naturally."

"On large wells it is best to run in a string of tubing, as large as is physically possible to get into the well and still leave sufficient annular space between the tubing and the casing, so as to restrict the flow of gas downward between these two strings of pipe as little as possible. As an example, 4-in. tubing or 4½-in. DBX casing can be run nicely inside the standard 6¼- or 6⅝-in. oil string, whereas, the use of 5³⁄₁₆-in. casing so restricts the input of gas as to prevent the proper volume reaching the bottom of the tubing; 5³⁄₁₆-in. casing, however, can be run nicely where the oil string is 8¼ in., or larger."

"In very large wells it is often considered impractical to run such tubing to the full desired depth on account of the high starting pressure required and it has become customary to stop at some such point as 1,500 or 2,000 ft. from the top. A large volume of gas is then turned into the casing head, the oil is displaced up through the tubing and the process is continued so that the oil is litterly 'slugged' out through the tubing at relatively high flowing pressures. In this way the operator is assisting the rock pressure in partially relieving it of the necessity of furnishing the energy required to lift the oil clear from the bottom of the hole. The rock pressure, thus partially relieved of this load, operates more efficiently. Less gas is wasted, more is left in the sand to produce additional oil at a later date, and the life of the property is prolonged. This conservation is represented by a reduction in the ratio of the gas coming from the sand to the barrel of oil produced."

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[1] Brundred, L. L., Practical Production of Oil by Gas Lift, *Oil Weekly*, Nov. 11, 18, 25, 1927.

"As to the physical preparation of the average flush well for the gas lift, especially in the so-called 'town lot' fields, the roads are generally such that it is impossible to move in large compressors, the time and space necessary to install such compressors is lacking, and the determination of the number of units to install cannot be made when only a few wells have been drilled on the property. Under such circumstances the operator has turned to the use of the so-called 'semiportable' belted or steam-driven compressors for this purpose. These can be hauled directly to the well, can be quickly connected, and from the data obtained from a number of such installations in the same field, the central plant can be laid out and erected for permanently flowing all the wells on the property. Properly installed, however, such a plant may be used as the central distributing plant, although the average efficiency is low."

"In many cases the practice has been to run small tubing and flow the well upward through the annular space between the casing and tubing. To be sure, it is easier to get the well started in this manner as the annular space between the 6 1/4- or 6 5/8-in. casing and 2- or 2 1/2-in. tubing, as commonly used, will contain the same amount of oil at considerably less height of fluid column than in the tubing, thus requiring less pressure to 'kick over' this lower static head. Once started in this manner, the operator has often continued flowing up between the casing and tubing, mainly on account of the lack of time necessary to experiment and thus determine the efficiency to be obtained by flowing such wells up through large-sized tubing."

"*Medium-sized Wells:* 400 *to* 1,000 *Bbl.*—Wells producing fluid in this volume should invariably be flowed upward through tubing and the method employed is almost identical with that to be described under the next classification, in that the fluid is atomized and carried out in the form of a fluid-laden spray. This, of course, can be done only by the injection of large volumes of gas in order to break up the oil sufficiently to atomize it."

"*Small Wells:* 5 *to* 400 *Bbl.*—In the case of wells of this size it becomes necessary to control the volume of gas injected into the well so carefully and closely as to obtain a constant unvarying pressure on the casing head. This is done only by the present-day volume controllers, recording pressure gages, and other instruments so necessary to furnish a 24-hr. picture of what is taking place at the bottom of the tubing. In view of the fact that almost anyone can 'blow' the average large well and even some of the medium-sized wells, no further consideration will be given to the description of such wells, and it must be understood that all statements hereafter made have to do with the more scientific principles involved and methods employed in handling the small wells or the lower range of medium-sized wells."

The general principles of the lifting process as stated by Miller[1] in describing California practice:

"Oil wells equipped for the gas-lift method of pumping are customarily tubed in such a manner that the flow of oil to the surface is either through the tubing or through the annular space between the tubing and the well casing. The usual procedure in California is to introduce the compressed gas into the casing at the casing head. The oil from the well, accompanied by gas from solution in the oil, and free gas from the formation, including extraneous gas pumped in, flows to the surface through the tubing. This mixture of oil and gas from the well flows directly into a gas trap where the gas is separated from the oil. The gas from the trap is conveyed in the intake line to a gasoline plant where, by a series of compressions, and cooling, the gasoline is recovered. In large installations, the wet gas from the wells after being compressed from approximately atmospheric pressure to 25 or 30 lb. per square inch, is passed through an absorption plant and then further compressed to 250 or more pounds pressure depending upon the required working pressure at the well."

"The above is a very general outline of the principles of the process of pumping oil from wells by the gas-lift method. Many variations of this method are in evidence throughout the oil fields of California. Sometimes portable compressors are used that take the wet gas directly from the gas traps, compress it, and recirculate it down the well. The excess gas from such systems is delivered through pop valves into the lease compressor and absorption plant intake lines. Still another method is to treat the gas from the well in a low-pressure absorption plant, then compress it to the required working pressure and circulate it down the well. This method is inefficient because a relatively high back pressure, 25 or more pounds, must be maintained in the gas traps in order to force the gas through the absorbers."

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[1] MILLER, H. C., Mechanical Installations for Gas-lift Pumping As Practiced in the California Oil Fields, *Petroleum Development and Technology*, p. 85, 1927.

Some operators who are primarily interested in the amount of oil obtained have proceeded upon the theory that if a little gas would lift some oil, more gas would increase the production accordingly. In actual practice, it has been found that a reduction in the amount of gas used will sometimes actually increase the output of oil.

In general, gas is introduced into casing at pressure and volume determined by needs of each particular well, and oil is flowed through tubing. The Marland engineers have designed a special packless casing head which is gas tight and is being used successfully. This casing head is so designed with tapered seat that tubing is hung directly from it, so that the greater the load on it the tighter it becomes. One of the Marland Company's applications in the Panhandle field was reported as follows:

"One of the wells chosen was the No. 1 Weatherly, in Sec. 19 M and C Survey, Hutchinson County. This well was making only 60 bbl. daily on the swab and had initial production of 300 bbl. It was declining rapidly at the time the experiment was begun. A two-stage compressor was installed and after several trials it was determined that a volume of about 600,000 cu. ft. of gas a day at 115 lb. pressure and a temperature of 225° F. gave best results. The well is making 50 bbl. daily and is holding steadily at that figure. The decline was halted, although production was not increased. With the beginning of the experiment on No. 1 Weatherly, gas was forced into the well between the casing and the 2-in. tubing, which ran to the bottom of the hole, and oil was flowed through the tubing. This was not satisfactory because paraffin soon clogged the tubing. The paraffin was deposited at the top of the tubing as the 'head' of gas was lost and the cold temperature at the surface was encountered. The process was reversed and the gas is put in through the tubing, flowing the oil between the casing and tubing."

The usual and common application of the air or gas lift is for the purpose of starting the flow and then regulating controllable conditions so as to secure the greatest production economically in a steady and continuous process. In most installations, the starting of the flow is an operation which should be avoided as much as possible, due to the possible bad effects of the high pressures on the producing formations. But systems of intermittent flowing of wells have been developed and successfully used, as shown by the following extracts from articles which have appeared from time to time in the technical press.

The theory of the intermittent flowing of wells by the air or gas lift, as given by Pierce and Lewis[1] follows:

"In Fig. 111 is shown the principles of the intermittent air lift. The fluid accumulates in the bottom of the well or in a chamber at the bottom of the well when the pressure is off the sand and then air pressure is let into the chamber, which forces the fluid down and up into the eduction pipe, a portion of the air passing through an aperture in the pipe and aerating the column above the injection point. The flow continues until the fluid is out of the chamber, whereupon it is necessary to let a new charge of fluid accumulate in the well."

One system is described by Miller[2] as follows:

"The intermittent or impulse system of flowing a number of wells from a single compressor plant of limited capacity is practiced to some extent in California. This method requires less compressor capacity than is necessary were each well flowing simultaneously. Six wells on a property in the Torrance field are being successfully flowed by the intermittent system. Three steam-driven compressors, under governor control, handling gas up to 350 lb. per square inch pressure furnish enough gas to operate these 6 wells which produce around 500 bbl. of 19 A.P.I. gravity oil daily."

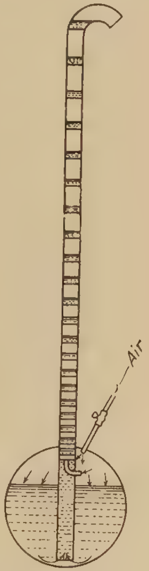

FIG. 111.—Principles of the intermittent gas lift. (*Pierce and Lewis.*)

"In the intermittent system, all the gas from the compressors is automatically turned into one well at a time and allowed to discharge into that well for a predetermined length of time. In this way the compressors build up sufficient pressure to flow the well, and after flowing, the gas under pressure passes on to the next well to secure like results. For this reason the compressor speed is regulated by governors. Distribution of gas from one well to another is accomplished by a clock-like contrivance which revolves as a dial, pins being placed at intervals which cause electric contact, which in turn effects the opening of small valves releasing pressure to actuate a trip placed at the manifold on the gas discharge line. As soon as the time limit for a certain well is reached the trip automatically causes a camshaft to revolve a portion of a turn and in doing so the projecting cams open a second valve by depressing the valve stem. This automatic time regulation changes the direction of the total flow of the gas from one well to another, at previously determined time intervals. In this manner, each well receives the full discharge of the compressors for approximately 3-min. periods, or each well of the six receives the full volume of gas about once every 18 or 19 min."

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[1] PIERCE, H. R., and J. O. LEWIS, Principles of the Air-gas Lift As Applied to Oil Production, *Petroleum Development and Technology*, p. 19, 1927.

[2] MILLER, H. C., Mechanical Installations for Gas-lift Pumping As Practiced in the California Oil Fields, *Petroleum Development and Technology*, p. 85, 1927.

It should be noted throughout that the writers describing the intermittent system stress the point that it is more economical than the continuous lifting of the oil. The following quotation[1] is given as an account of experiences in connection with this subject:

"While its successful operation is generally known, the economical operation of the gas lift has not received the proper attention of operators. There are many instances where the gas-oil ratios of individual wells using the gas lift are excessively high resulting in an uneconomic use of gas, and in many cases back pressure is built up which retards the maximum flow of oil into the well."

"As each individual well represents entirely different production conditions, the gas requirements for each well must be determined separately. One well might require the introduction of gas under 200 lb. pressure for a period of 3 min. with an interval of 15 min. for the accumulation of the normal fluid level of oil in the well; while another will produce sufficient oil to operate efficiently under a 500 lb. gas pressure with gas introduced for 2 min. periods and requiring but 2 min. accumulation intervals."

"A process which has been recently devised and has been found to efficiently and economically handle wells of this type is now in use on several California leases. On several installations where this device, known as the 'K & G Gastributor,' has been installed, it has been found that the compressor capacity necessary to flow wells prior to installation of the gastributor was sufficient to handle additional wells and still give increased oil production and saving of gas over previous operations."

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[1] Zimmerman, C. A., Intermittent Flowing by the Gas-lift Process Increases Production and Saves Gas, *Oil Age*, p. 36, September, 1927.

"The gas is introduced to the wells with the gastributor in the same manner as under ordinary gas-lift installations. In some cases a specially designed packer, shown in the accompanying illustration, is used to relieve the pressure of the formation gas so that no back pressure will be built up to restrict the free flow of oil into the well. This packer conducts the formation gas up around the macaroni string and introduces it into the tubing at a point above the packer where it is also used in assisting the lifting of the oil from the hole. A check valve is installed at the casing head on the input gas line."

"The fluid level of the oil in the well at the time required for accumulation of the fluid head of each well is determined by the usual methods. Then, by means of the gastributor, which is described below, the gas is delivered to each well intermittently according to the well requirements. In this way several wells may be flowed by one compressor installation, obtaining the maximum oil production with the minimum gas introduction."

"The action of the gas when using intermittent flow is vastly different from the action of the gas on continuous flow. On continuous gas-lift flow special footpieces and other devices are employed to diffuse the gas throughout the oil column in the eduction tube. The principle of operation by this method is to decrease the weight of the fluid by the induction of gas bubbles. By this method a considerable pressure loss is sustained due to slippage of gas bubbles through the oil."

"When flowing intermittently the full efficiency of the gas pressure is obtained. The column of oil, when flowing intermittently, is in effect a solid plunger, under which the column of gas is introduced en masse, the gas being forced into the eduction tube under sufficient pressure and volume to force the fluid out through the eduction tube. By this method there is practically no slippage of the gas through the oil."

"The gastributor is a mechanical device with electric connections to a magnetically operated valve in the gas line. The magnetically operated valve (Fig. 112) is intermittently opened for the flow period and closed for the accumulation period by means of a special timing apparatus, patents for which are pending and on which most of the major claims are said to have been allowed the inventors, according to Jordan and Taylor, production specialists, manufacturers of the gastributor. The valve used for this purpose opens and closes instantaneously."

"Any number of wells up to 24 can be operated from one gastributor connected to a central compressor station. The time intervals for flowing and accumulation of oil can be regulated accurately by seconds with the special timing apparatus. By connecting up a bank of lights, each light representing an individual well, the operator can tell from a glance which well is being flowed and has a check on the timing apparatus."

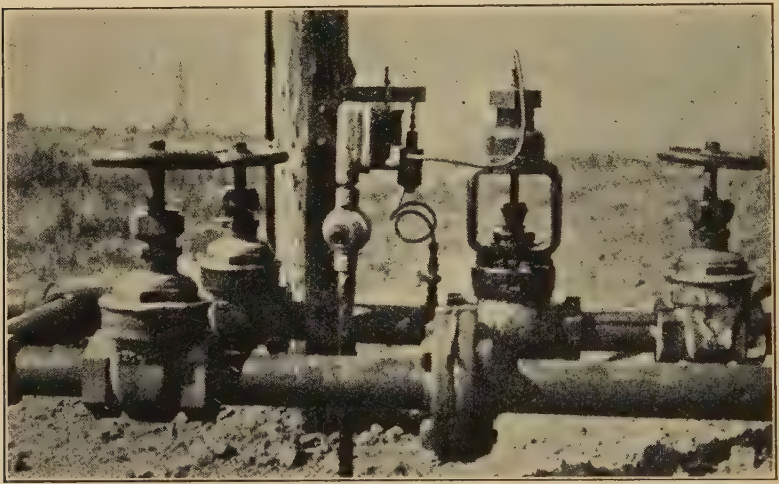

Fig. 112.—Magnetically operated quick closing valve hookup on gas line for intermittant flowing. (*The Oil Age.*)

"The special packer (Fig. 113) which is used in connection with the gastributor utilizes a new design of packer, employing either lead or asbestos as the packing material. Both of these materials are said to have given satisfactory seal under tests, with the additional advantage of not showing any tendency to stick or bind on the pipe."

"An inlet is provided in the lower end of the packer which admits the formation gas. Gas entering the packer is conducted up through the packer and between the macaroni string, where it discharges into the tubing above the packer."

"A standing valve is provided below the packer, which permits the oil to enter the eduction tube when the gas from compressors is cut off from the well. When the oil has reached the normal fluid level of the well and the gas is conducted from the compressors into the bottom of the eduction pipe, the standing valve closes and cuts off any entrance for the compressor gas to the formation, thus eliminating any possibility of building up a back pressure on the oil sands."

"The production curves of wells shown in the accompanying graph (Fig. 114) picture the increase of production resulting from intermittently flowing the wells. The production of each well from completion to the end of August is given, showing the marked increase in production obtained after putting the wells on the intermittent flow with the gastributor."

"Well No. 5, noted on the graph (Fig. 114), which came in with an initial production of 627 bbl., showed a steady decline over a 3 weeks' period prior to installing the gastributor, dropping to a daily production of 330 bbl. After putting on the gastributor, this well immediately jumped to 551 bbl. The decline curve for this well has since shown a considerably more gradual decline than prior to putting on the intermittent flow."

"In every well the increase in production has been quite noticeable after installing the gastributor. Well No. 16, which was completed with the gastributor, shows a more gradual decline than the wells brought in on the gas lift with steady flow."

"The gastributor requires no attention after it is once set, except for the application of a little oil once a day. It has been found to be positive in action and entirely dependable."

"Figure 115 represents the action of this type of lift installation and control."

B. H. Scott[1] published the following comments relative to the low fluid level well:

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[1] Scott, B. H., Application and Function of Production Methods and Production Equipment, *Oil Field Eng.*, p. 26, August, 1927.

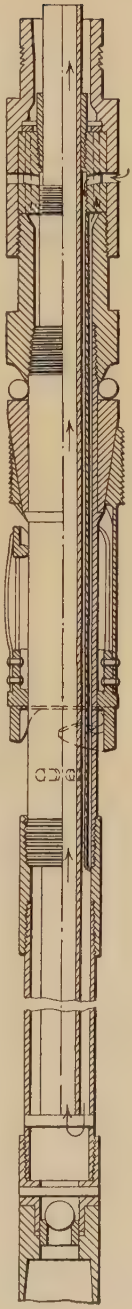

Fig. 113.—Macaroni tube and packer. (*Robinson.*)

"In making gas-lift installations in wells which have a low fluid level, it has been found that by placing a special packer immediately above the perforations in the casing, tightly packing off the perforated pipe from the upper blank pipe (Fig. 116), in

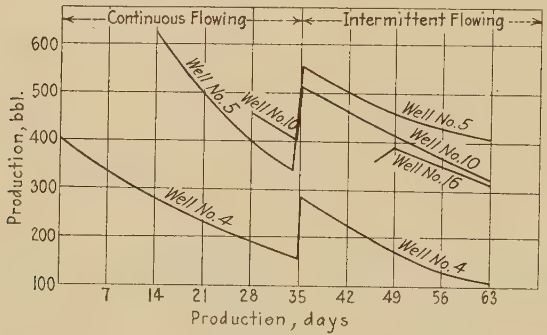

FIG. 114.—Type decline curves. (*Zimmerman.*)

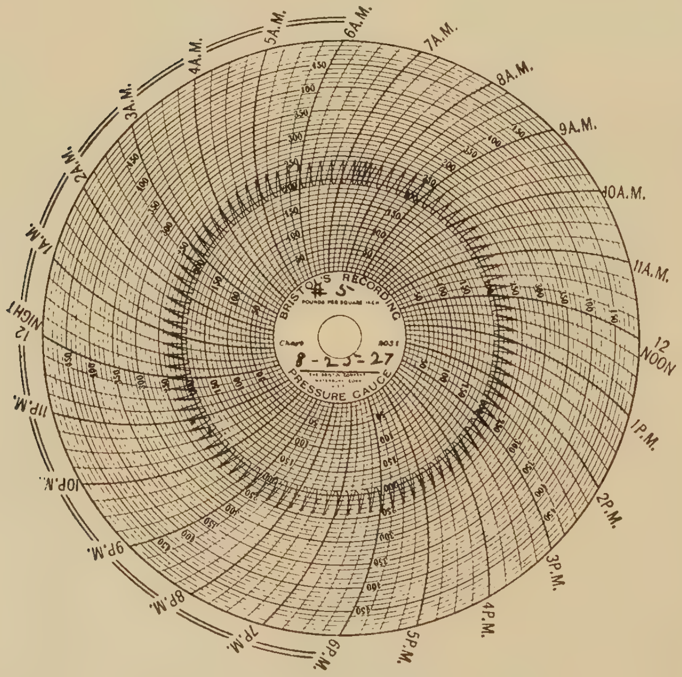

FIG. 115.—Typical action of an intermittent lift. (*Zimmerman.*)

many instances good results can be obtained. The procedure followed in such cases is to place a special packer on the tubing at the desired point, immediately above which a special by-pass nipple is screwed into the tubing string. This nipple is perforated to permit the flow of gas to enter the tubing. A $1\frac{1}{4}$-in. pipe is supported inside the special by-pass nipple, and is packed off within the nipple at the upper end, to prevent the gas from flowing upward in the tubing at this point. The $1\frac{1}{4}$-in. pipe extends downward to, and is screwed onto, the footpiece. The compressed gas is forced down into the casing, and through the perforations in the special by-pass, continuing down through the annular space between the outside of the $1\frac{1}{4}$-in. macaroni and the inside of the tubing to the perforations in the footpiece, at which point the flow of gas through the perforations mixes with and lightens the oil, the mixture traveling upward through the macaroni to the tubing proper. This packer system apparently has overcome the difficulty encountered in wells that produce a small amount of production with the gas lift installed.

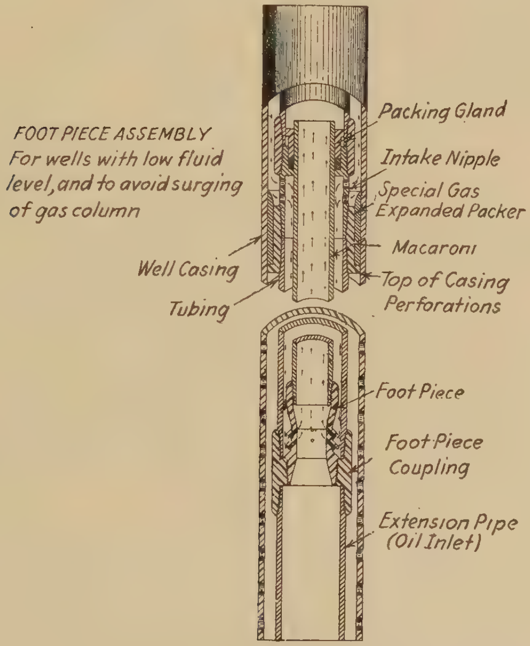
FOOT PIECE ASSEMBLY
For wells with low fluid
level, and to avoid surging
of gas column
Packing Gland
Intake Nipple
Special Gas
Expanded Packer
Macaroni
Well Casing
Tubing
Top of Casing
Perforations
Foot Piece
Foot Piece
Coupling
Extension Pipe
(Oil Inlet)

FIG. 116.—Special packer and macaroni tube. (*Scott.*)

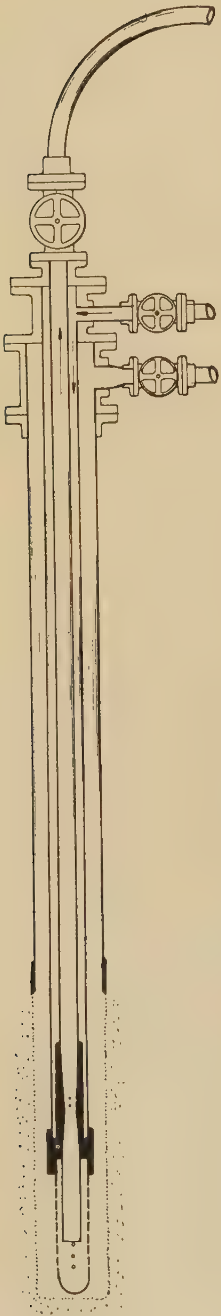

FIG. 117.—Air lift with Regan well head equipment. (*Pennington.*)

If the volume of production is small, it is necessary, with the ordinary gas-lift system, to force an unnecessarily large volume of gas through the well, which procedure causes a 'heading' condition, resulting in the gas volume surging with the flow, and thereby expending the energy of the compressed gas column intermittently without obtaining the desired result."

And Pennington[1] describes the air-lift pump as follows:

"For securing finely divided bubbles, the writer uses the gas-lift pump shown in Fig. 117. The seat B is run into the well on a string of pipe, and the nozzle C is then run inside the first line until the lower end of the nozzle rests on the seat, inclosing the space between the two lines. Air or gas is then admitted at the surface to travel down between these two lines, so that the operating pressure may be held independently of back pressure required on the well, and flow of oil-air mixture is up the inner line."

"In wells with rock pressure that we wish to hold as long as possible for forcing oil toward and into the well, this footpiece permits pumping with such operating pressure as required by submergence, without interfering with the necessary back pressure for preventing unduly large oil-gas ratios, and in wells where rock pressure has subsided on account of withdrawals of oil and gas, the operating pressure of the lift is not carried on the formation, for the operating pressure is, in this design, independent of the formation pressure. Some formations will not produce when back perssure is carried for pumping purposes, after the rock pressure has subsided."

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[1] PENNINGTON, HARRY, Lift Efficiency Depends upon Skill in Design and Operation, *Oil Weekly*, p. 41, Aug. 19, 1927.

"The double-line design shown has been effective in preventing casing troubles when heated air is used for eliminating accumulations of paraffin and tar in the flow line, for carrying heated air or gas down the outer line, between it and the inner line, prevents direct contact of heated air with casing so that casing expansion due to heat is minimized."

"A footpiece cannot, within itself, deliver high efficiency without correct proportioning of the remainder of the installation, for, as stated before, velocity of uptake is a major factor. The air lift then resolves itself into a proposition of:

Finely divided air or gas bubbles.

Correct uptake velocities.

Low-expansion ratios for avoiding excessive velocities at exit.

And when these are well balanced, there can be but one answer, which is reasonable efficiency."

Compressors and Compression.—The main purpose of this section is not to go into the theory of compression, which is fully covered in a number of technical books[1] and publications, but to assemble some ideas and data on the practical phases of the compressor plants, their types, and sizes, with a few notes on their operation as affected by some of the possible lift requirements.

Sufficient volume of gas at pressures up to 300 or more pounds per square inch is required for pumping oil wells by the gas-lift method. This gas may be obtained from high-pressure gas wells, as is done in several places in California, or taken from a low-pressure source of supply and its pressure raised by means of compressors. No two compressor installations operate under the same conditions because gas volume and pressure requirements differ for each well. Wells that respond to the gas-lift method of pumping generally require the maximum volume of gas when first placed on the gas lift or soon thereafter. The working pressures also are usually greatest at the time the well is placed on the gas lift. Moreover the starting pressures required are often two or more times the working pressures so that individual compressor installations must be designed to meet the maximum gas volume and pressure requirements. For this reason, many compressors now in operation have a much greater capacity than is necessary for efficient operation. Unless the cylinders are frequently changed, so as more nearly to satisfy the changed pressure and volume requirements, or the speed, at which the compressors are operated, altered, there necessarily will be a waste in operation. Because of this inefficient operation of individual units, large central compressor plants are used for gas-lift purposes wherever possible.

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[1] The theory of compression is fully covered in LUCKE, "Engineering Thermodynamics," McGraw-Hill Book Company, Inc., and quoted in LICHTY, "Natural Gas," John Wiley & Sons. A. and Z. DAW, "Compressed Air Power," Issac Pitman & Sons, covers the subject in much less detail but in a very clear manner. There are a number of technical books and publications available on the subject, one of the best of which, "Compressed Air Data," by W. L. SAUNDERS, issued by the Ingersoll-Rand Co., treats the subject in a most practical and useful manner; it also gives the theoretical data relative to the compression of gas.

Summarized quotations will first be given, as taken from some of the recent articles presented to the technical society meetings and published in the technical press.

R. W. Bond,[1] Production Engineer of the Roxana Petroleum Corporation, in discussing compressor equipment, stated:

"During the early development of the system, the equipment used generally consisted of small tandem compressors of about 250 cu. ft. per minute displacement, driven by automotive type gas engines, using a short belt drive. These compressors were first installed at the individual wells more as an experiment than anything else."

"After these first experimental installations had proved the method a success, it was considered economically advisable to centralize the compressor equipment in strategically located stations. However, as the information in regard to 'gas-lift flowing life' was anything but definite, and the most optimistic estimates in regard to it did not exceed 6 months, portability of equipment was still the first consideration in the minds of many operators. For this reason, a large proportion of the operators continued to install small semiportable type compressors in their centralized stations."

"The electric motor came rapidly into use as the prime mover for the small compressors as electric power became available in the fields. The operating cost of the electric motor is greater than of the automotive type gas engine for the same power output, but the greater continuity of service will tend to balance the extra cost."

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[1] Bond, R. W., Mechanical Equipment of Air-gas Lifts in Oklahoma and Kansas, Exclusive of Seminole, *Petroleum Development and Technology*, p. 71, 1927.

"Aside from the semiportable units, a number of strictly portable compressors were used. These consisted of automotive type gas engines direct connected to vertical compressors. The unit was assembled on one base and could be mounted on wheels or skids as desired. The chief objection to them, in the writer's opinion, was their small capacity: approximately 150 cu. ft. per minute, which made it necessary to use two, three, and sometimes more units per well, thus making the installation rather costly. However, they have been found valuable for test purposes and emergencies, where installation time is an important factor."

"When the compressors were first centralized, some operators decided to sacrifice portability in favor of larger volume per unit and installed duplex compressors, belt driven by slow-speed gas engines. This type did not prove very popular and comparatively few of them are in use. The present trend in large compressor equipment is the direct-connected duplex, driven by twin cylinder gas engines. Probably the most common size is the 180-hp. unit."

"In addition to the larger direct-connected units, there are in use a number of smaller semiportable direct-connected units. These consist of a vertical tandem compressor, driven by a vertical slow-speed gas engine with an interchangeable head so that oil may be used for fuel if so desired. The capacity is about the same as the semiportable belt-driven types."

"It is the writer's belief that future developments will show a merging of the large direct-driven type compressors with the small semiportable type belt driven by electric motor or automotive type gas engine. The small units will be installed first on account of their greater portability and will be in use while the larger units are being set. After the peak load has passed, the smaller units may be transferred to other districts, while the large permanent type takes care of the needs of the field, including any further demand for pressure or repressuring projects."

"The possibilities of combining gasoline plant and gas lift stations must be kept in mind. This plan is in use to some extent in the Seminole field at present."

Shaw,[1] in describing the general Seminole installations stated: "Two general types of compressors are in use in this field, one being a small electric or gas-motor compressor, the other is a larger type usually direct driven from gas engines, though there are a few installations of the larger type driven by belts from gas engines. The sizes and makes of compressors of the small type mostly employed are as follows:

Manufacturer	Size	Cubic feet, displacement	Revolutions per minute
Ingersoll-Rand Co	9½ by 4 by 10	243	300
Ingersoll-Rand Co	10 by 4¼ by 10	270	300
Chicago Pneumatic Tool Co	10 by 4¼ by 10	242	275
Worthington Pump & Machinery Corporation	10 by 4¼ by 12	270	250

"Makes and sizes of the larger types of compressors mostly employed in this field are as follows:

Manufacturer	Size	Cubic feet, displacement	Revolutions per minute
Bessemer Gas Engine Co	9¾ by 5 by 20	311	180
Bessemer Gas Engine Co	13½ by 6¼ by 20	585	180
Bessemer Gas Engine Co	14¼ by 6¼ by 20	653	180
Clark Bros	14 by 7¼ by 20		
Clark Bros	15 by 7¼ by 20		
Cooper	14½ by 7½ by 20		
Cooper	16 by 7¾ by 20		
Cooper	10 by 5½ by 20		
Ingersoll-Rand Co	15 by 6¾ by 16	486	150

"At the end of July, 1927, the various plants of the Carter Oil Company consisted of the following compressors:

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[1] Shaw, S. F., Air-gas Lift Practice in the Seminole Field, *Petroleum Development and Technology*, p. 100, 1927.

Make	Size	Number of compressors	Drive
Ingersoll-Rand Co.	9½ by 4 by 10	185	100 hp. electric motor
Ingersoll-Rand Co.	10 by 4¼ by 10	...	100 hp. electric motor
Chicago Pneumatic Tool Co.	10 by 4¼ by 10	2	75 hp. electric motor
Worthington Pump & Machinery Corp.	10 by 4¾ by 12	4	100 hp. electric motor
Bessemer	13½ by 6¼ by 20	58	165 hp. gas engine direct

"The Ingersoll-Rand compressor driven by electric motor has been found to be the most satisfactory, owing to the greater flexibility and dependability of this type of compressor, particularly in the early stages of air-gas lift operations. After pressures have declined to a low point, and it is desired to operate the wells by gas rather than by air, the Bessemer compressors driven by gas engines have been found to be quite serviceable, and the cost of compressions per 1,000 cu. ft. of gas or air is considerably less than when using the electric motor-driven type."

The Sinclair Oil and Gas Company in their Seminole operations used one cylinder of the two-stage tandem type of machine which was installed in a stand-by unit for their well starting operation. Gas from the well flowing supply header at the operating pressure (about 250 lb.) was furnished this cylinder and, depending upon the cylinder used, practically any kick-over pressure desired could be delivered to the starting header. A safety or relief valve was set in the discharge side so that unsafe pressure could not be built up in the starting system.

Swarts[1] stated in regard to Seminole practice:

"Starting pressures, working pressures, and cubic feet of gas or air used per well per day were important factors in selecting compressor equipment. The plants ranged in size from the small portable plants of three compressors to the larger semipermanent and permanent plants having as many as 30 compressors. The size of compressors range from 9½ by 4 by 10 in. in the smaller plants to 16 by 8 by 20 in. in the larger plants. The number of wells to be flowed and the amount of gas required per well per day determined the number and size of compressors. Very few tests were made on wells to determine the amount of air or gas required per day and installations were usually made according to the average input per well per day as determined by previous operations. Three to four small compressors 9½ by 4 by 10 in.; two 80 hp. compressors 9¾ by 5 by 20 in.; or one 160 hp. 15 by 7¼ by 20 in. were used per well. The size of cylinders could be changed on the larger compressors allowing for changes in plant capacity. The above sizes were capable of delivering 800,000 cu. ft. of gas or air per day at working pressures up to 500 lb. and starting pressures up to 1,000 lb. Compression was always two stage."

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[1] Swarts, C. R., Mechanical Installations for Gas-air Lifts in the Seminole Area, *Petroleum Development and Technology*, p. 79, 1927.

"The smaller compressors were belt driven with 75 or 100 hp. electric motors whereas the larger sizes were direct driven with gas engines."

"Compressor equipment must be large enough to perform at pressures ranging from 200 to 500 lb. per square inch."

"Higher pressures are often required to 'break-out' wells, and compressor equipment must be capable of performing safely at such pressures as 750 and 1,000 lb. during the 'break-out' period. Some companies doing a great deal of gas lift work install special plants, consisting of one or two large high-pressure compression units, which are used only for the purpose of breaking out, or starting the well flowing, after which the running pressure is furnished by the smaller machines. The general types of compressor equipment have been extensively employed. The larger type and larger capacity is low-speed equipment. The smaller type, as related to displacement capacity, is of the high rotative speed type. In use, these two types seem to be fairly evenly divided. These compressor installations are more extensively propelled by gas engines and electric motors than by steam and oil engines."

"The light, high-speed, multicylindered gas motor belt-driving compressors have been adopted in the Seminole area to a large extent. One of the prime considerations in the installation of compressor and engine equipment is that of portability. In the Seminole fields, where installations were hurriedly constructed and installed during the late fall, winter, and spring of last year (1926), and compressors, engines, etc., were brought into the area by scores, not to say hundreds, during the height of development, then the matter of portability was, if not essential, at least very important. In other fields where the writer has visited, gas-lift surface equipment has been generally a little larger and heavier than at Seminole."

H. C. Miller[1] gave the following information on California practice:

"1. *Portable and Semipermanent Installations.*—Many operators use one or more gas-engine, electric-motor, or steam-driven compressor units for bringing in, testing, and pumping individual wells. These units are usually mounted on four-wheel trucks or on skids and can be readily and easily moved from well to well. Such portable equipment is generally for temporary use only. It is moved to another well as soon as a permanent installation is completed, or the well has been tied into the gas line from a central compressor plant. The compressors of portable units are usually either duplex, or straight-line tandem, two-stage machines. Low-pressure gas cylinder diameters range from 8 to 12 in. High-pressure cylinder diameters range from 4 to 6 in. and the length of strokes from 8 to 12 in. The majority of portable and semipermanent units in California use 8 by 4 by 8-in. compressors running at a speed of about 250 r.p.m. The size of gas engines and motors for portable units varies according to the power requirements of the compressor. Gas engines rated at 40 to 60 hp. and electric motors up to 100 hp. are generally used on portable compressor units. A few semipermanent units are steam-driven, straight-line machines with 9-in. low-pressure and 4-in. high-pressure gas cylinders, 12-in. steam cylinders and 10-in. stroke."

"2. *Permanent Installations.*—Few large compressor plants have been built in California primarily for furnishing compressed gas for flowing oil wells. On most properties, compressor plants had been built, before the advent of the gas lift, to recover gasoline from the casing-head gas and to compress the gas to pressures high enough to buck the line pressures in the commercial gas companies' gas-collection systems. This pressure varies usually from 250 to 325 lb. per square inch. These companies furnish gas for domestic and industrial purposes to cities in the Los Angeles Basin, San Joaquin Valley cities and towns, and to consumers in Santa Barbara and Ventura counties."

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[1] Miller, H. C., Mechanical Installation for Gas-lift Pumping As Practiced in the California Oil Fields, *Petroleum Development and Technology*, p. 85, 1927.

"The problem of furnishing gas to flow wells by the gas-lift method on properties where a compressor plant is in operation is, therefore, a simple matter. The addition of a gas-distributing header with individual lines to the wells, or a gas-distributing system consisting of main lines about the property with individual lines to the wells, the installation of a booster compressor where high starting pressures are necessary, and the installation of gas volume-control apparatus at each well where the manually operated central-header system is not to be used constitute the only added facilities required."

"The Richfield steam-driven compressor plant of the Union Oil Company of California consists of 19 Chicago Pneumatic single-stage, direct-connected, steam-driven compressors. Thirteen of these units are 10 by 10 by 10-in., five are 10 by 7 by 10-in., and one is a 10 by 6 by 10-in. compressor for starting or booster purposes; also, used in conjunction with the five 7-in. machines when starting pressures are not required. Each compressor is driven by one 80-hp. Broderick return tubular boiler."

"The wet gas from the wells at 10-in. vacuum is first compressed in a separate compressor plant to 30 lb. per square inch and circulated through an absorption plant where its gasoline is recovered. The intake gas to the thirteen 10 by 10 by 10-in. units in the steam-driven plant is taken from the absorption plant discharge line at 20 lb. and compressed to 140 lb. per square inch."

"The 7- and 6-in. compressors then take this gas at 130 lb. pressure and further compress it to a pressure of 325 lb. per square inch. This plant delivers 8,000,000 cu. ft. of gas per day at 325 lb. pressure to an 8-in. distributing header equipped with Wescott recording meters and gate valves for controlling the volume of gas to each well. These meters are located at the header on the 3-in. individual lines to the wells. The booster compressor is connected to the distributing header in such a manner that high-pressure gas may be delivered to any one of the 19 or more wells."

"The gathering system that brings the wet gas from the gas separators at the wells to the low-pressure compressor and absorption plant consists of main lines from the well traps."

"The new Richfield gas-driven compressor plant of the Union Oil Company of California consists of four 320-hp. and one 640-hp. Worthington direct-connected compressors. The 320-hp. machines have 16-in. intermediate and 9½-in. high-pressure cylinders: the 640 compressor has a 22-in. intermediate and a 13-in. high-pressure cylinder. The length of stroke on all machines is 20 in. The diameter of the gas-engine cylinders is 18½ in. The 320-hp. compressors are each equipped with two and the 640-hp. machine with four of these 18½ by 20-in. gas cylinders, each of which is four cycle, double acting."

"As at the Richfield steam plant, the intake gas to the gas-driven plant is taken from the absorption plant discharge at a pressure of 20 lb. per square inch. The discharge from the intermediate cylinders enters the high-pressure cylinders at 80 lb. and is discharged at a pressure of 325 lb. per square inch. The capacity of this plant is 12,000,000 cu. ft. of gas per day at 325 lb. pressure."

"A compressor plant installation for flowing four wells at Cat Canyon, Santa Barbara County, Calif., consists of two Ingersoll-Rand two-stage compressors with 12 by 12-in. low-pressure and 6 by 12-in. high-pressure cylinders. The compressors are driven by 110-hp. Bessemer gas engines, size 13½ by 18 in. The intake gas enters the low-pressure cylinders at atmospheric to 3 lb. per square inch pressure and is compressed to approximately 100 lb. From the low-pressure cylinders the gas passes through a cooling tower where a small amount of gasoline is recovered. The gas is then compressed to about 500 lb. per square inch in the 6 by 12-in. cylinders and delivered to the main distributing line. The individual lines to the wells take off from this distributing line. As each well operates under slightly different volume and pressure, volume regulating control valves are installed on each of the individual lines to the wells. After the gas passes through the control valves it is preheated to about 200° F. before it enters the well casing."

To avoid installing a compressor which would supply pressure enough for starting but which after the flow was started would be working at a much lower pressure, various means and devices have been employed. A portable high pressure compressor can be used for starting and the working compressor employed for running. If the tubing is so arranged, it can be lifted for starting purposes and then lowered as the flow takes place. Swabbing has been resorted to in some cases. The process of rocking or alternately applying pressure to the tubing and casing has been developed. A two-stage compressor with a capacity usually of 250 cu. ft. per minute and capable of withstanding a working pressure of 400 lb. per square inch or more is the first requisite. From 50 to 75 hp. is necessary to drive the compressor. Steam, gas, or electricity is used, as most convenient. Several wells can be flowed from a single large compressor if specially designed volume and pressure regulating devices are installed in the pipe line.

The capacity of a compressor depends primarily upon the cylinder size, low-pressure cylinder in case of compound units, and the number of piston strokes per unit of time, usually the minute. These two items taken together constitute what is called the "displacement" and is the volume displaced per minute by the piston when doing the work of compression. If there were no physical clearance necessary and the intake air or gas did not rise in temperature when coming in contact with the warm or hot compressor cylinder walls, the displacement would represent the machines' delivery, but, in practice, the actual compressed air or gas delivered is less than the machines' displacement. The ratio of the actual volume delivered, or the capacity, to the displacement, or indicated delivery, is called the "volumetric efficiency." The following quotation is from Lucke's[1] discussion of the subject of volumetric efficiency:

"Volumetric efficiency is defined as being the ratio of low-pressure capacity to displacement. On a diagram the displacement is represented on the volume scale by the horizontal distance between verticals through the extreme ends of the diagram. Since there are three ways in which the low-pressure capacity may be approximated or determined, there are a corresponding number of expressions for volumetric efficiency."

"1. The volumetric efficiency of the hypothetical cycle is

$$E_v \text{ (hypothetical)} = \frac{\text{(hypothetical L.P. Cap.)}}{\text{(displacement)}}.$$

"2. The apparent volumetric efficiency is

$$E_v \text{ (apparent)} = \frac{\text{(apparent L.P. Cap.)}}{\text{(displacement)}},$$

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[1] LUCKE, C. E., "Engineering Thermodynamics," p. 157, McGraw-Hill Book Company, Inc., 1912.

and would be very nearly equal to the true volumetric efficiency were it not for leakage, valve resistance and heating during suction.

"3. The true volumetric efficiency is

$$E_v \text{ (true)} = \frac{\text{(true L.P. Cap.)}}{\text{(displacement)}}.$$

"In problems of design or prediction it is necessary either to find dimensions, speeds, and power necessary to give certain actual results, or with given dimensions and speeds to ascertain the probable power and capacity or other characteristics of actual performance. Since it is impossible to obtain actual performance identical with the hypothetical, and since the former cannot be computed, the most satisfactory method of estimate is to perform the computations on the hypothetical cycle, and then to apply to these results factors which have been found by comparing actual with hypothetical performance on existing machines as nearly like that under discussion as can be obtained. This necessitates access to data on tests performed on compressors in which not only indicator cards are taken and speed recorded, but also some reliable measurement of gas compressed."

As Saunders[1] states:

"When compressors were bought and sold on the 'swept' volume of the air cylinders, the volumetric efficiency was a matter of great importance to the purchaser. Nowadays compressor contracts are usually based on compressor output, and, provided that the compressor yields its full specified output of air, the volumetric efficiency is of little interest to the user. So long as the purchaser obtains the specified output of air compressed to the required pressure by the consumption of not more than the specified amount of steam or electrical energy, he need not trouble himself about the volumetric efficiency, or any other of the various efficiencies which are so often quoted."

Tables XXXIV and XXXV show, for Cooper compressors, the cylinder sizes for various pressure combinations and the capacities, which term is understood to mean the actual delivery of air and not displacement as above defined.[2]

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[1] Quoted from Compressed Air Data by W. L. SAUNDERS, through the courtesy of the Ingersoll-Rand Company.

[2] See LICHTY "Natural Gas," pp. 329–330, for similar data and further discussion of this subject.

TABLE XXXIV.—CYLINDER SIZES OF COOPER TWIN-TYPE COMPRESSORS[1]

Suction pressure, gage	Discharge pressure, gage																									
	80		100		120		140		160		180		200		225		250		275		300		325		350	
15 in. V	21½	11½	20¾	10½	20	9¾	19½	9¼	19	8¾	18½	8¼	18¼	8	18	7¾	17¾	7⅜	17½	7⅛	17¼	6⅞	17	6¾	16¾	6½
10 in. V	20	11½	19¼	10½	18½	9¾	18	9	17½	8½	17	8¼	16¾	7⅞	16½	7½	16¼	7¼	16	7	15¾	6¾	15½	6½	15¼	6⅜
5 in. V	19	11½	18	10⅜	17¼	9½	16¾	9	16¼	8½	16	8¼	15¾	7⅞	15½	7½	15	7¼	14¾	7	14½	6¾	14¼	6½	14¼	6¾
0 lb	12¼		17¼	10⅜	16¾	9½	16	9	15½	8½	15¼	8⅛	15	7¾	14½	7⅜	14¼	7	14	6¾	13¾	6½	13¾	6⅜	13½	6¼
5 lb	11¾		11		10½		15	9	14½	8½	14	8	13¾	7¾	13½	7⅜	13¼	7	12¾	6¾	12¾	6½	12½	6¼	12¼	6
10 lb	11½		10¾		10		9½		9¼		13¼	8	13	7¾	12½	7⅜	12¼	7	12	6¾	12	6½	11¾	6¼	11½	6
15 lb	11½		10½		9¾		9½		9		8¾		12½	7¾	12	7¼	11¾	7	11½	6¾	11¼	6½	11	6¼	11	6
20 lb	11½		10½		9¾		9¼		8¾		8½		8¼		8		11¼	7	11	6¾	11	6½	10¾	6¼	10½	6
25 lb	11½		10½		9¾		9		8¾		8¼		8		7¾		7½		10¾	6¾	10½	6⅜	10¼	6⅛	10	6
30 lb	11¾		10½		9¾		9		8½		8¼		8		7¾		7½		7¼		7		10	6⅛	9¾	6
35 lb	12¼		10¾		9¾		9		8½		8¼		7¾		7½		7¼		7		6¾		6¾		9¾	6
40 lb	12¾		10¾		9¾		9		8½		8		7¾		7½		7¼		7		6¾		6½		6½	
45 lb	....		11¼		9¾		9		8½		8		7¾		7½		7¼		6¾		6¾		6½		6¼	
50 lb	....		....		10		9¼		8½		8		7¾		7¼		7		6¾		6¾		6½		6¼	
60 lb	....		....		....		9½		8½		8		7¾		7¼		7		6¾		6½		6¼		6¼	
70 lb	....		....		....		...		8¾		8¼		7¾		7¼		7		6¾		6½		6¼		6	
80 lb	....		....		....		...		...		8½		8		7½		7		6¾		6½		6¼		6	
90 lb	....		....		....		...		...		...		8		7½		7		6¾		6½		6¼		6	
100 lb	....		....		....		...		...		...		8¼		7½		7¼		6¾		6½		6¼		6	

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[1] Below heavy lines both cylinders are the same size and compressor is single stage.

TABLE XXXV.—CAPACITIES AT STANDARD CONDITIONS OF COOPER TWIN-TYPE COMPRESSORS[1]

Suction pressure, gage	Discharge pressure, gage												
	80	100	120	140	160	180	200	225	250	275	300	325	350
15 in. V	940,000	852,000	756,000	736,000	692,000	659,000	629,000	594,000	574,000	557,000	533,000	511,000	495,000
10 in. V	1,097,000	993,000	916,000	847,000	802,000	755,000	723,000	689,000	656,000	631,000	605,000	586,000	566,000
5 in. V	1,240,000	1,115,000	1,023,000	963,000	903,000	842,000	803,000	771,000	733,000	697,000	673,000	648,000	626,000
0 lb....	1,073,000	1,242,000	1,136,000	1,058,000	978,000	930,000	890,000	834,000	792,000	761,000	733,000	706,000	689,000
5 lb....	1,412,000	1,186,000	1,015,000	1,244,000	1,139,000	1,077,000	1,028,000	980,000	932,000	888,000	847,000	823,000	781,000
10 lb....	1,779,000	1,466,000	1,230,000	1,110,000	988,000	1,216,000	1,173,000	1,095,000	1,060,000	980,000	948,000	918,000	872,000
15 lb....	2,155,000	1,745,000	1,483,000	1,338,000	1,172,000	1,049,000	1,950,000	1,218,000	1,135,000	1,091,000	1,060,000	996,000	950,000
20 lb....	2,538,000	2,059,000	1,745,000	1,506,000	1,360,000	1,230,000	1,119,000	1,006,000	1,244,000	1,180,000	1,138,000	1,098,000	1,060,000
25 lb....	2,989,000	2,390,000	1,990,000	1,720,000	1,515,000	1,415,000	1,269,000	1,145,000	1,039,000	1,296,000	1,282,000	1,172,000	1,115,000
30 lb....	3,525,000	2,720,000	2,271,000	1,955,000	1,716,000	1,558,000	1,415,000	1,266,000	1,170,000	1,072,000	1,000,000	1,242,000	1,190,000
35 lb....	4,275,000	3,170,000	2,520,000	2,192,000	1,923,000	1,720,000	1,480,000	1,413,000	1,308,000	1,186,000	1,089,000	1,031,000	1,267,000
40 lb....	5,190,000	3,645,000	2,950,000	2,430,000	2,158,000	1,903,000	1,221,000	1,540,000	1,399,000	1,303,000	1,187,000	1,113,000	1,041,000
45 lb....	....	4,282,000	3,257,000	2,729,000	2,348,000	2,055,000	1,990,000	1,669,000	1,543,000	1,393,000	1,295,000	1,202,000	1,129,000
50 lb....	....	....	3,738,000	2,988,000	2,545,000	2,270,000	2,071,000	1,839,000	1,650,000	1,550,000	1,395,000	1,302,000	1,228,000
60 lb....	....	....	....	3,678,000	3,090,000	2,671,000	2,381,000	2,112,000	1,920,000	1,743,000	1,600,000	1,484,000	1,392,000
70 lb....	....	....	....	....	3,725,000	3,168,000	2,792,000	2,437,000	2,280,000	1,993,000	1,825,000	1,693,000	1,560,000
80 lb....	....	....	....	....	....	3,730,000	3,260,000	3,840,000	2,480,000	2,222,000	2,018,000	1,880,000	1.560,000
90 lb....	....	....	....	....	....	....	3,772,000	3,170,000	2,791,000	2,478,000	2,314,000	2,115,000	1,965,000
100 lb....	....	....	....	....	....	....	4,285,000	3,520,000	3,169,000	2,792,000	2,543,000	2,318,000	2,153,000

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[1] Below heavy lines compressor is single stage. For sizes, see Table XXXIV.

TABLE XXXVI.—TABLE OF BAROMETRIC HEIGHTS, ALTITUDES, AND PRESSURES

Adapted from Smithsonian Tables

Standard barometer		Altitude, feet above sea level	Pressure, pounds per	
Inches	Centimeters		Square inch	Square feet
17.0	43.18	15,379	8.350	1,202.3
17.2	43.69	15,061	8.448	1,216.6
17.4	44.20	14,746	8.546	1,230.7
17.6	44.70	14,435	8.645	1,244.8
17.8	45.21	14,128	8.742	1,259.0
18.0	45.72	13,824	8.840	1,273.2
18.2	46.23	13,523	8.940	1,287.3
18.4	46.73	13,226	9.038	1,301.4
18.6	47.24	12,931	9.136	1,315.6
18.8	47.75	12,640	9.234	1,329.7
19.0	48.26	12,352	9.332	1,343.8
19.2	48.77	12,068	9.430	1,357.9
19.4	49.28	11,786	9.529	1,372.1
19.6	49.78	11,507	9.627	1,386.3
19.8	50.29	11,230	9.726	1,400.4
20.0	50.80	10,957	9.825	1,414.6
20.2	51.31	10,686	9.922	1,428.7
20.4	51.82	10,418	10.020	1,442.9
20.6	52.32	10,153	10.118	1,457.0
20.8	52.83	9,890	10.217	1,471.2
21.0	53.34	9,629	10.315	1,485.3
21.2	53.85	9,372	10.414	1,499.4
21.4	54.36	9,116	10.511	1,513.6
21.6	54.87	8,863	10.609	1,527.7
21.8	55.37	8,612	10.707	1,541.8
22.0	55.88	8,364	10.806	1,556.0
22.2	56.39	8,118	10.904	1,570.1
22.4	56.90	7,874	11.002	1,584.3
22.6	57.40	7,632	11.100	1,598.4
22.8	57.91	7,392	11.198	1,612.6
23.0	58.42	7,155	11.297	1,626.7
23.2	58.92	6,919	11.395	1,640.8
23.4	59.44	6,686	11.493	1,655.0
23.6	59.95	6,454	11.592	1,669.3
23.8	60.45	6,225	11.690	1,683.3
24.0	60.96	5,997	11.788	1,697.4
24.2	61.47	5,771	11.886	1,711.6
24.4	61.98	5,547	11.984	1,725.7
24.6	62.48	5,325	12.083	1,739.9
24.8	62.99	5,105	12.182	1,754.0
25.0	63.50	4,886	12.280	1,768.2
25.2	64.01	4,670	12.377	1,782.3
25.4	64.52	4,455	12.475	1,796.5
25.6	65.02	4,241	12.573	1,810.7
25.8	65.53	4,030	12.671	1,824.8

Barometric heights are given in inches and millimeters of mercury at its standard density, 32° F.

Altitudes are heights above mean sea level in feet, at which this barometric height is standard. (See Smithsonian Tables for corrections for latitude and temperature.)

Pressures given are the equivalent of the barometric height in pounds per square inch and per square foot.

The normal atmospheric pressure can be taken as 14.7 lb. per square inch or 30 in. mercury at sea level. At altitudes above sea level where the atmospheric pressure and, consequently, the low pressure to which the gas expands, is less by approximately 1 in. mercury or 0.49 lb. per square inch for each 1,000 ft. increase in altitude, the air is less dense; that is, 1 cubic foot of air weighs less. Table[1] XXXVI is useful for finding the pressures theoretically existing at different altitudes.

As the density of the atmosphere decreases with the altitude, a compressor located at a high altitude will take in a smaller weight of air at each stroke. The reduction of pressure at the inlet affects the power expended in compressing the air, but the decrease in power required does not vary in the same ratio as the decrease in capacity. For this reason, compressors to be used at high altitudes should have the steam and air cylinders properly proportioned to meet the varying conditions at different levels.

The relation between pressure and volume of air delivered by compressor at sea level and at higher altitude is as follows:

Let P = final gage pressure in both cases.
P_1 = initial gage pressure at sea level.
P_2 = initial gage pressure at higher altitude.
V_1 = final volume at sea level.
V_2 = final volume at higher altitude.

$$\frac{V_2}{V_1} = \frac{1 + \frac{P}{P_1}}{1 + \frac{P}{P_2}}.$$

The expansion from some certain high pressure to a lower atmospheric pressure will result in a larger volume of free air or gas than if the sea level pressure of 14.7 lb. per square inch obtains, but, due to the lower intake pressure of a compressor, more air, *i.e.*, a greater volume of air will be required to do the same amount of work. This can be understood from the fact that the compressors do less work at the higher altitudes, and, naturally, the same amount of work cannot be done where less capacity for work exists.

An estimating rule is to allow 3 per cent increase of volumetric requirements for each 1,000 ft. increase in altitude. This will cover the requirements for all practical purposes.

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[1] From Lucke, "Engineering Thermodynamics."

Shaw[1] gives the following table:

TABLE XXXVII.—PERCENTAGE INCREASE OF AIR REQUIRED TO LIFT 1 GAL. OF WATER 1,000 FT. IN ADDITION TO THE QUANTITY GIVEN IN TABLE XXIV

Altitude, feet	100 pounds	200 pounds	300 pounds	400 pounds	500 pounds
	Percentage				
1,000	2.1	2.6	2.8	2.8	2.9
2,000	4.4	5.4	5.6	5.7	5.8
3,000	6.8	8.0	8.4	8.6	8.8
4,000	9.3	10.3	11.4	11.7	11.2
5,000	11.8	13.8	14.5	15.0	15.3
6,000	14.3	16.8	17.4	18.0	18.7
7,000	17.0	19.7	20.6	21.3	21.9
8,000	19.8	22.9	24.0	25.0	25.5

The question of power required for compression has been worked out in many ways and numerous tables are available for the solution of this problem. Leaving out the theoretical development of the formulæ, the working formulæ,[2] considering only the adiabatic compression which is most nearly approached in practice, are given here for air and various gases:

Let $I.H.P.$ stand for the required indicated horsepower per 100 cu. ft., of piston displacement per minute.

P_1 = the absolute initial pressure, pounds per square inch.
P_2 = the absolute discharge pressure, pounds per square inch.
$R = P_2/P_1$.
n (air) = 1.406.

Work required to compress air:
Single stage, $I.H.P._{(1)} = 1.512P_1(R^{0.29} - 1)$.
Two stage, $I.H.P._{(2)} = 3.024P_1(R^{0.145} - 1)$.
Three stage, $I.H.P._{(3)} = 4.536P_1[R^{0.0966} - 1]$.

In gas compression, the required power will vary with the gas itself, for the value of n is different for each gas. The following data apply to the designated gases and to single-stage compression. For compound compression, the equation should be modified as the foregoing air equation is modified.

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[1] SHAW, S. F., "Oil-well Blowing," p. 21, Ingersoll-Rand Co.

[2] Taken from "Compressed Air Data" by W. L. SAUNDERS, through the courtesy of the Ingersoll-Rand Company.

Gas	n	*I.H.P.* per 100 cu. ft. displacement per minute
Air..................	1.406	$1.512P_1(R^{0.289} - 1)$
Carbon dioxide.......	1.400	$1.528P_1(R^{0.286} - 1)$
Natural gas..........	1.315	$1.823P_1(R^{0.239} - 1)$

The *I.H.P.* per 100 cu. ft. of piston displacement per minute as figured from the foregoing equation, in practice, will be slightly higher than the actual required power due to the physical inability of a cylinder to deliver but a fractional part of its indicated displacement. The extra power needed for the operation of valves, that lost in friction, etc., tend to make the required power approach the above values with still a small working margin of safety left by the use of the above equation.

Power required will vary with the altitude at which a machine is working, becoming less as the altitude increases. Tables showing the values of this factor compared to the sea-level power requirements are given in the engineering handbooks.[1]

The matter of power requirements when the overall efficiency of the particular installation is taken into consideration may be described by means of examples as follows: Lifting oil from a well requires the expenditure of power or a certain amount of work in a certain length of time. To lift 1 barrel of oil weighing 300 lb. from the bottom of a 3,000 ft. well requires the expenditure of 900,000 ft.-lb. of work and if this work be done in 1 min. of time, the power requirements will be 900,000 ÷ 33,000 or 27.2 hp.

A 100 per cent efficient installation need develop only this 27.2 hp. to lift the above barrel of oil; but, as a 100 per cent efficiency is impossible in practice, additional power must be available to do the work required. The additional power required must be available in inverse proportion to the actual working efficiency of the installation. In other words, if the overall efficiency of the installation is 50 per cent, the power required will be $27.2 \div 0.50 = 54.4$ hp.; a plant of 30 per cent efficiency would require $27.2 \div 0.30 = 90.7$ hp.; and a 10 per cent efficiency, which is nearer the actual figure in practice, would require 272 hp. per barrel. The great increase in power requirements with the lowering of the overall efficiency then becomes apparent.

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[1] See "Compressed Air Data," pp. 31–40, Ingersoll-Rand Co.

It may be well to mention, at this point, that the compressed or high-pressure gas, which accompanies the oil, supplies some of the required power for lifting that oil; the compressor installation, therefore, need not be designed to do all the work. The formational gas is just as capable of doing work during its expansion to a lower pressure as is the gas compressed in machines and introduced into the well. To show this idea by means of an example:

Take a 1,500-bbl. well (1.04 bbl. per minute) producing 33.3 A.P.I. gravity oil (300 lb. per barrel) from a depth of 3,000 ft. Work required per minute is

$$\left(\frac{300 \times 1.04 \times 3{,}000}{33{,}000}\right) = 28.4 \text{ hp.}$$

Assume 1,500,000 cu. ft. of gas is taken from the trap daily and that the compressor furnishes 750,000 cu. ft. of this while the remaining 750,000 cu. ft. comes from the formation. If 20 per cent of the formational gas is in solution and is freed in the trap, 600,000 cu. ft. is left to do work or a total of 1,350,000 cu. ft. per day, or 930 cu. ft. per minute. In expanding from a working pressure of 200 lb. to atmospheric pressure, this gas is capable of performing 194 hp. of work.

The efficiency of the system is then

$$28.4 \div 194 = 15 \text{ per cent.}$$

The compressor furnishes about 56 per cent of the total work. If the work furnished by the formational gas is left constant and the efficiency of the installation is raised to 25 per cent, an increase of 10 per cent, the power required will be 114 hp. of which 86 hp. is still furnished by the gas from the formation, leaving $114 - 86 = 28$ hp. to be supplied by the injected gas. Allowing for the same 20 per cent solubility factor, the actual requirement would be, probably, a plant of $28 \div (1.00 - 0.20) = 35$ hp. per barrel compared to 109 hp. per barrel for the 15 per cent efficiency. The more efficient plant is about one-third as large as the other plant and probably the lifting costs are one-third to one-half of the former lifting costs.

The relations between volumes, pressure, and temperature for the working conditions, where adiabatic compression can be assumed for all practical purposes, may be developed from the following equations where n = the ratio of the gases' specific heats and where subscript 1 refers to the initial condition and subscript 2 to final condition:

$$\frac{P_2}{P_1} = \left(\frac{V_1}{V_2}\right)^n; \frac{V_1}{V_2} = \left(\frac{P_2}{P_1}\right)^{\frac{1}{n}}.$$

$$\frac{V_1}{V_2} = \left(\frac{T_2}{T_1}\right)^{n+1}; \frac{T_2}{T_1} = \left(\frac{V_1}{V_2}\right)^{n-1}.$$

$$\frac{P_2}{P_1} = \left(\frac{T_2}{T_1}\right)^{\frac{n}{n-1}}; \frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}}.$$

The pressures in the foregoing formulæ are absolute; temperatures are thermometric plus 460° F.; and the volume includes the actual clearance volume as well as the swept volume.

The following notes[1] are modified by the writer for present purposes. The compression efficiency of a compressor is the ratio of the theoretical power required to compress the amount of air actually delivered to the actual power developed in the compressing cylinder, as shown by indicator diagrams. If the theoretical power is based upon isothermal comparison, the efficiency is then known as "isothermal compression efficiency." For convenience, the factors may be expressed per 100 cu. ft. of free air delivered per minute. If the theoretical power is based on adiabatic compression, the efficiency is known as "adiabatic compression efficiency." It is becoming more customary to compare horsepower to the isothermal indicated horsepower factor.

The "mechanical efficiency" of compression is the ratio of the air indicated horsepower to the steam indicated horsepower in the case of a steam-driven and to the brake horsepower in the case of a power-driven machine. The difference between the two represents excess power required to overcome frictional resistance of the machine, which is largely dependent upon the design and workmanship and the supervision received when in operation. It represents a loss which is, however, smaller than might be expected. The mechanical efficiency of a well-designed air compressor ranges between 90 and 95 per cent.

The "overall efficiency" of a compressor is the product of the items "compression efficiency" and "mechanical efficiency." This is the item that most interests the buyer because it expresses a ratio between the amount of actual air he gets and the power input. In the case of a steam-driven compressor, the overall

[1] Mainly from "Compressed Air Data," Ingersoll-Rand Co.

efficiency is found by multiplying the compression efficiency by the mechanical efficiency. In the case of a power-driven compressor the overall efficiency is obtained by multiplying the compression efficiency by the mechanical efficiency and then by the overall efficiency of the prime mover, including belt and idler, if used, the result being the machine's overall efficiency from the power input back to the theoretical power required.

A guarantee of overall efficiency should be accompanied by a statement giving the theoretical horsepower base used, isothermal or adiabatic. The purchaser of an air compressor should remember that the theoretical horespower to the adiabatic base is higher than theoretical horsepower to the isothermal base and, consequently, the overall and compression efficiencies to the adiabatic base are higher than the same efficiencies to the isothermal base for the same machine under given conditions.

When the performances of compressors are contrasted, the only satisfactory basis of comparison is the overall efficiency. When a comparison is made between steam-driven compressors running under similar conditions of steam supply and air output, the number of cubic feet of free air compressed per pound of steam consumed is a very convenient figure for the overall efficiency. The equivalent figure for an electrically driven compressor is the number of cubic feet of free air compressed per kilowatt input to the motor. These expressions are, however, unsuitable when compressors operating under dissimilar conditions are compared, and it is better to state the overall efficiency as the ratio of the theoretical power required for the air delivered to that supplied to the engine or motor driving the compressor.

There is a natural tendency on the part of manufacturers, whose machines may show a specially good intermediate efficiency, to make the most of that particular feature; but each stage in the process of compression should be equally good, if a high overall efficiency is to be obtained.

As brought out by one writer:

"To lift 1 bbl. of 38 gravity oil 100 ft. requires 0.883 hp. of actual work in foot-pounds, and to lift the same barrel 3,000 ft. requires 26.49 hp. of work, if the work is done in 1 min."

"With a plant efficiency of 10 per cent, the plant would therefore, be required to develop 264.9 hp. per barrel of oil and at 5 per cent efficiency, 529.8 hp. so that at low-operating efficiencies, the size of the plant and the cost are materially affected by well piping design, distribution line design, as well as compressor and engine mechanical efficiency, and compressor volumetric efficiency."

"The overall efficiency is the one measure of actual obtained efficiency, and the term 'overall efficiency,' according to the writer's views, is that obtained by adding to the power output of engines driving compressors the power represented by formation gas produced with the oil, allowing formation gas the same unit of compression power per 1,000 cu. ft. as required by compressed gas, and dividing the sum so obtained into the foot-pounds of work done in lifting oil to the surface. In electric-driven compressor plants, the consumed power would be measured on the high side of transformers, or where power is metered for payment, which methods include in the computation the motor and transformer efficiency and are entirely correct."

"This is the familiar wire-to-water efficiency method customarily used in power-plant work.

"Tests made on the deliveries of air compressors have disclosed that assumptions as to their delivery, horsepower, and efficiency founded upon manufacturers' claims and ratings are very unreliable and conclusions based upon such data should not be accepted. As operated in the field, a compressor is not of the same efficiency as when tested on the floor of the factory. Analogous errors have been noted in other observational data, and until the information gathered in the field is more complete and dependable progress in air-lift engineering will not be satisfactory."

Concerning the matter of overloading a compressor, which practice is often done due to an immediate necessity occurring, Jordon[1] stated:

"The real danger under these conditions is not generally understood by operators, neither do they understand why the temperature of air under like conditions is much higher during compression than that of natural gas. So a few words of explanation and warning might be in order and possibly save some lives and much property."

"To demonstrate the difference in rise of temperature between air and gas due to compression, we will cite a few instances.

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[1] Jordon, E. W., Air and Gas for Compressing Flowing Oil and Placing Pressure on the Oil Sand, *Nat. Petroleum News*, p. 292, Sept. 21, 1927.

At 5 compressions the rise of temperature of air is 307° F., and the temperature rise of gas is 210° F. At 10 compressions the temperature rise of air would be 496° F. while the rise of temperature for gas would be 324° F."

"To the above temperatures is to be added the actual atmospheric temperature less 60° F., as, for example, if the atmospheric temperature is 105°, deducting 60°, we have 45°; 496° plus 45° equal 541°."

"Now, in designing compressors for changeable pressure conditions, the capacity and horsepower requirements are usually based on the normal working conditions or the volume and pressure conditions at which the compressing unit will be likely to work most of the time. So, if during a short period of time this unit is required to work at a discharge pressure several times greater than the normal discharge pressure, it would be necessary to reduce the volume of air or gas handled."

"This in the past has usually been done by reducing the intake pressure. This in turn unbalances the load and sets up extremely high-temperature conditions in the high-stage cylinder. A 165 hp. unit compressing air from zero to 350 lb. should carry cylinders 13½ by 6¼ by 20 in. at 190 r.p.m. and deliver approximately 730,000 cu. ft. of free air per 24 hr. Ordinarily, if it is necessary to increase the discharge pressure to 1,000 lb., it would be accomplished by reducing the intake pressure to 10-in. vacuum, reducing the volume of delivery to 413,000 cu. ft. free air, an intermediate pressure of 35 lb. gage, ratio of compression of 5.21, a temperature rise for first stage 320° F. The second stage would have a ratio of 20.5, final pressure 1,000 lb., the temperature rise would be 720° F. This is entirely too high temperature to take a chance on, as it will gasify most any ordinary gas engine oil and set up a very touchy explosive mixture. Lower temperatures have been known to cause very destructive explosions."

"The remedy for such a condition is an adjustable clearance in the compressor cylinders, which some of the older compressor builders are already incorporating in their cylinders. This not only permits the operator to balance the load and temperatures but to hold the load up to the full normal horsepower of the compressing unit at all times, and under all varying pressure conditions. As an example of balancing the load and temperatures by using a variable clearance:

"By increasing the clearance of the cylinders, the volume handled is reduced to the ability of the available horsepower to handle and still maintain zero intake, this would give an even ratio of compressions for each stage. From zero to 1,000 lb. the total number of compressions is 70.5. The ratio of each stage equals the square root of 70.5 or 8.4. This would give each stage a temperature rise of 442° F. Although this temperature is still too high for good practice, it is not nearly so dangerous as the preceding condition, and it is advisable to use an exceedingly good grade of cylinder oil to prevent carbonizing and creating trouble with the valves."

"In the matter of compressing gas, where the temperature for air is given as 320° F., for gas it would be 155° F., and where the temperature for air is stated as 720° F., for gas it would be 457° F. In the balanced load condition where the temperature rise is 442° F. for air, for gas it would be 289° F."

"In the above conditions it is assumed that there is efficient cooling between stages, and all figures are based on 14.4 lb. as absolute zero pressure."

"Considering the foregoing facts we most earnestly warn all users of compressors, especially where air is being compressed, to consult the compressor manufacturers' engineers before taking chances on unusual conditions."

If gas alone is being compressed, as long as the pressures are kept within the safe strength of compressor and connecting piping, there would be no liability of explosion or bad effect other than low efficiency or carbonizing of the lubricating oil, which would cause bad action of the valves. Of course, if the gas is being taken in under a vacuum, unless great care is taken with the piping connections and all packing is kept tight, there is always a possibility of taking air in with the gas and creating a combustible or explosive mixture.

An example of the overloading of compressors is to be seen in the practice of holding a trap pressure of 10 to 15 lb. which may result in a pressure of 5 lb. above atmospheric at the compressor intake. This increases the capacity of the machine by, say, one-third, and reduces the total required capacity but, at the same time, it greatly increases the required power to operate the compressor.

Gas Recirculation.—A gas-lift compressor station comprises some of the most expensive parts of a compression gasoline plant. Due to the necessity for keeping the equipment readily portable, however, and also to the economy based upon the payout period, producers have been reluctant to install the additional auxiliary equipment necessary to make gasoline. The auxiliary equipment necessary is adequate cooling and accumulator tanks in both the high and low stage, gasoline traps, and storage tanks.

This subject was discussed in a paper presented at the Fort Worth meeting of the Petroleum Division A.I.M.M.E. by Gibbs and Taylor,[1] who described the California practice. The following excerpts are taken from that paper:

"Before the advent of gas lift the gas-production curve of a field showed a peak during the flush production with a rapid decline as the wells were put on the pump and then a long steady decline curve of a relatively small volume of rich gas for the life of the field. Under the gas-lift method of production instead of having the sharp decline at the end of the flush production period, sufficient circulating gas would be turned to the wells as needed so as to keep up the required total gas-oil ratio. The gas production curve then assumes a long gradual decline giving a large volume of gas for treatment for several years to come."

"The gas decline curve will not follow that of the oil as the lowering of the rock pressure by the steady production of oil and gas from the sand will make it necessary to continue using the large-sized tubing and circulate large volumes of gas in order to keep as low as possible a back pressure against the sands."

"In tracing the flow (Fig. 118) of the gas from the time it leaves the well until it again enters through the casing head, under high pressure, we get a very good idea of the complex distributing and regulating system that must be installed and the large treating and compression plants that are made necessary."

"Gas traps must be of sufficient size to efficiently separate large quantities of gas and oil and should be elevated sufficiently to enable the oil, if being produced steadily, to flow to the gage tanks under its own head. Traps equipped with automatic gas and oil control valves are very satisfactory as line pressure is practically maintained in the trap except at such time as heading may require more pressure to force the oil into the tanks. The elevation of gas traps and their operation under low pressure serves the double purpose of aiding in the circulation of the well by reducing tubing pressure and also aids in the conservation of the gasoline vapors that would otherwise be lost as tank vapors."

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[1] GIBBS, R. D., and C. C. TAYLOR, Handling Recirculated Gas, *Petroleum Development and Technology*, p. 49, 1927.

"Gas gathering and distributing lines should be large enough to cut down line drop to a reasonable amount. The elimination of all possible pressure drop is very important. Instead of handling large quantities of gas during the flush production period only, the gas-lift method of production insures us large volumes of gas over a much longer period of time. The cost of large lines is soon paid for by the saving of compression which would otherwise be necessary in order to offset the line drop."

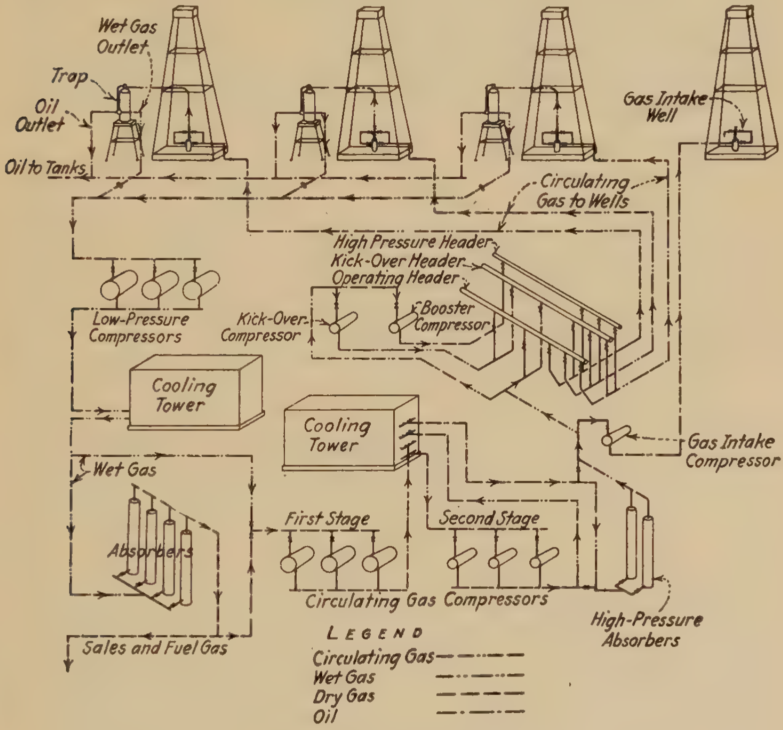
Wet Gas Outlet
Trap
Oil Outlet
Oil to Tanks
Gas Intake Well
Circulating Gas to Wells
High Pressure Header
Kick-Over Header
Operating Header
Booster Compressor
Low-Pressure Compressors
Kick-Over Compressor
Cooling Tower
Cooling Tower
Gas Intake Compressor
Wet Gas
Absorbers
First Stage
Second Stage
Circulating Gas Compressors
High-Pressure Absorbers
Sales and Fuel Gas
LEGEND
Circulating Gas
Wet Gas
Dry Gas
Oil

Fig. 118.—Flow sheet of gas lift system. (*Gibbs and Taylor.*)

"Gas-lift requirements have made necessary the development of more accurate regulating and volume-control devices. Keeping a constant pressure and an adequate volume of gas at important points in the system presents no simple problem. In most fields a continuous supply of excess gas is being sold or blown to the air. A back-pressure regulator at this point occupies the key position in the regulating system as it insures the required pressure and volume throughout the entire system. Where there is any possibility of the demand for circulating gas and fuel, etc., exceeding the total amount returned from the field, an emergency line from some outside source should be connected into the system through a regulator that will open up when the pressure drops below a certain point."

"Meters should be installed on the gas lines to and from each well and to and from any point in the system where shrinkage is liable to occur. In this way, an intelligent gas balance can be made each day."

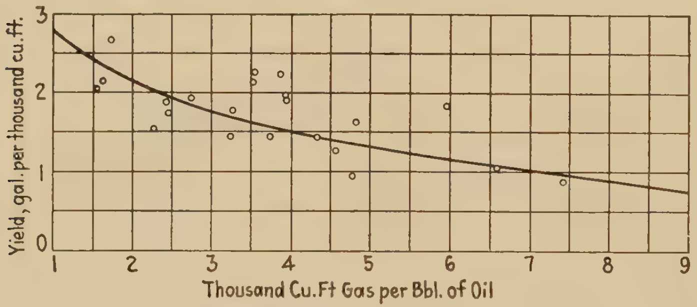

Fig. 119.—Relation of gasoline content of gas to gas-oil ratio. (*Gibbs and Taylor.*)

"Surging of the gas from the field which is caused by any heading of the individual wells causes trouble in the compressor and absorption plants. This is usually controlled by efficient operation of the wells, except in fields where the water cut is high. Unless tubing sizes can be increased with additional water content, heading cannot be avoided."

"Although the total extractable gasoline from circulated wells is much more than could be obtained under other operation, the yield per 1,000 cu. ft. is always less. This calls for increased proportional absorber capacity in the absorption plants."

"The gasoline content of the wet gas will vary with the total gas-oil ratio. This was shown by plotting curves with data from several leases in the Dominguez field, Fig. 119."

"Much discussion has arisen regarding the increased natural gasoline production from a field that is being operated by gas lift. There seems to be considerable difference of opinion as to whether this gasoline, if left in the oil, would reach the refinery stills or would evaporate from the oil in transit and storage, thus representing a true saving if extracted in the natural gasoline plants."

"It would be supposed that the extractable gasoline in a formation gas would be in equilibrium with the crude oil from which it originated, and that the introduction of dry gas and the enrichment of that gas with further extractable gasoline would include gasoline fractions of a higher boiling range. It will be noted that in plotting gallons of gasoline to total barrels of oil and gasoline produced in several fields that the curve follows very closely the gas circulation curve for the same field. For example: In the Richfield district we find about a 50 per cent increase in gallons of gasoline, which would indicate that some of the higher boiling gasoline fractions were being included in the gas."

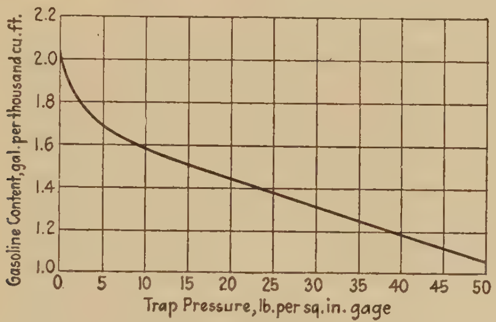

FIG. 120.—Average decrease in gasoline content of gas due to increased trap pressure, on nine wells in the Brea district, California. (*Gibbs and Taylor.*)

"The estimated production figures for the Southern Division of the Union Oil Company of California, from July 1, 1925, to June 30, 1926, which were made up from normal decline curves, showed a natural gasoline recovery of 7.5 bbl. per 100 bbl. of oil. Gas-lift method of operation was entered into extensively and the actual production was 9.6 per 100 bbl. of oil."

"Tests of oil from some wells have shown a lower gravity after being put on circulation. Others were of practically the same gravity. The gasoline content of the gas from a well will vary considerably with trap pressures as is shown by Fig. 120. The change in pressures may have some bearing on these discrepancies. Any increase in the percentage of emulsion might also affect it."

"In order to obtain more accurate information on this subject, tests were run on a group of wells in one of our districts. Four wells, of comparable physical characteristics, were selected and tested over a period of 24 hr. Two of these wells were gas-lift producers, one being a flowing well and the other a pumper. Gas volumes were measured and tested for gasoline content. Crude samples were taken from the traps and tanks and distilled. Engler distillations and vapor-pressure tests were made on the condensates. The results are what might be expected, the additional amounts of natural gasoline from the gas-lift wells checking closely the amount of gasoline stripped from the oil as disclosed by distillation of the oil samples. Crude samples from the tanks taken after the oil had stood in the tanks for 24 hr. showed no appreciable loss over that period of time."

"In deciding upon the most profitable installation of natural gasoline extraction equipment, many factors should be taken into consideration. Trap pressures, gravity of the oil, condition of the gage and storage tanks, distance from the refinery and the number of times the oil is handled enroute, elapsed time between its production and its arrival at the refinery stills, and the demand for natural gasoline are all influences that should be given careful consideration. The amount of stabilizing done in the absorption plant and the method of transporting gasoline also enters into the problem."

"If one wishes to have the proverbial 'bird in the hand' safe in the gasoline storage tanks, an absorption plant of sufficient size to treat all of the gas efficiently must be installed. All gas from the low-stage compressors will go directly to the absorbers, the circulating compressor plant and the various fuel lines, etc., being supplied with gas from the absorber discharge. With dry-gas circulation aftercooler coils need not be installed in the circulating compressor plant cooling tower. Circulation of a well with hot gas is considered a decided advantage. In addition to reducing paraffin troubles, it also tends to reduce the viscosity of the oil."

"If it is thought best to hold down the amount of natural gasoline produced per barrel of oil, the compressor plant can be connected for either partial or entire wet-gas circulation. With ample intercooler and aftercooler coils, a 300-lb. compressor plant operating on wet gas should extract an appreciable amount of the condensable gasoline. This gasoline is of a fairly stable nature and can be used to good advantage for blending with the absorption gasoline. With the usual hook-up, the compressor plant intake does not have to stand the effects of the absorber pressure drop if wet-gas circulation is used."

"There seems to be little controversy as to the advisability of recirculating gas, especially in fields of low-gas production. But a question has arisen as to the advisability of taking the gasoline from the recirculated gas. This appears to be a question of operating policy which must be determined for each case on its own merits, and for which no general rule can be laid down. Various engineering and economic considerations enter into the problem to such an extent that it is believed that the one best method of solution of the problem is to try it and learn from experience, based on various existing conditions, as to which is the proper policy for that particular case."

"If there is a market for the gasoline and the storage is of such a character and capacity as to make the gasoline sales profitable, that is, where no excessive amount is lost due to evaporation, the profit so secured, after allowing for the necessary 'write offs' on the plants, etc., and operating expenses, should be compared with the drop in value of the oil, due to its lower gravity resulting from the stripping of the higher fraction from the oil."

Roy O'Neal[1] stated as follows:

"A recent compilation shows that 841,500 gal. of natural gasoline per day, or 44 per cent of the natural gasoline output in Oklahoma and Kansas, is being manufactured at greater Seminole. According to the Bureau of Mines statistics, 13 per cent more natural gasoline was made in December, 1927, than in December, 1926, and 74 per cent of this increase was contributed by Oklahoma and Kansas. Considering the gas-lift installations in Tonkawa, Garber, and the fields around Wewoka in Oklahoma, Oxford field in Kansas, Panhandle and other fields in Texas, one would be safe in estimating that probably 1,000,000 gal. of natural gasoline per day is being recovered from gas used in gas lift which formerly found its way to market through crude pipe lines and refineries or was lost through evaporation."

"The investment in the plants in the Seminole field was made primarily for the production of oil by the use of the gas lift.

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[1] O'Neal, Roy, Effect of Gas Lift on Oil and Gas, *Oil and Gas Jour.*, p. 121, Feb. 16, 1928.

The natural gasoline recovered is simply a by-product made incident thereto and of more or less minor importance."

"Although the price of natural gasoline will probably follow fairly close to that of the gasoline made from crude oil, still it will depend in the immediate future upon gas-lift operations in Seminole. The natural gasoline output there is not expected to parallel the decline of oil production. In gas-lift installations as the production and rock pressure declines the gas-oil ratio of the lift is increased. When the Seminole City pool was first put on gas lift, only about 1,000 or less cubic feet per barrel was necessary to lift the oil, but as the rock pressure declines a lower pressure and a larger volume of gas is used, so that now at some wells as much as 7,000 cu. ft. per barrel of oil lifted is used. This removes a corresponding greater quantity of gasoline from the oil, even the gasoline content of gas is less. When wells are put to pumping in the Seminole field, the yield of natural gasoline has in some cases dropped to 20 per cent of that when gas lift was used."

"In Oklahoma, most of the prospective sources of oil are from the deeper horizons, consequently we may expect more oil to be produced by means of the gas lift and more natural gasoline made from this source."

"It appears to the writer that a natural gasoline plant, built and operated under present prices, where the gas must be handled by compressors, and where there is no other revenue excepting through the sale of gasoline, will in few occasions prove profitable. That is, if prices remain approximately as they now are a gasoline plant which gathers the gas with compressors to be profitable must be used in conjunction with gas-lift operations, restoration of pressure as in Smith-Dunn process, or for boosting low-pressure gas, so that the surplus may be sold for domestic or industrial consumption or in connection with a carbon black plant."

"The recirculation of saturated gas, by returning to the input high-pressure gas, the gasoline which has condensed out during the process of compression, will tend to maintain the oil's natural gravity and possibly increase it somewhat. Some authorities maintain that this is the proper policy to follow if the greatest possible ultimate recovery is to be obtained. The matter should be put on a dollars and cents basis and determined from that viewpoint."

Some of the advantages to be secured from returning the condensed gasoline to the sand are: slight increase in volume of oil; higher gravity than when stripped; less trouble from wax; reduced viscosity and greater consequent production; cleaner sand and lessened resistance to flow with maintenance of fairly steady volume of gas production.

In some instances where the gasoline plant is of the compression type and operating under sufficiently high pressure, the wells are flowed with gas direct from the gasoline plant. The very interesting description of such an installation which happens to be a cooperative proposition, since the production is under the control of one company and the gasoline extraction compression plants under the control of a different company, was given by George Reid:[1] This article is quoted here:

"The Forrest E. Gilmore Company, Tulsa, has completed the construction of three high-pressure plants in the Bowlegs field, Seminole area, which are operated for the dual purpose of preparing natural gasoline and providing gas at sufficient pressure to be employed in the artificial flowing of oil wells under the gas-lift system. The plants are located on the producing properties of the Atlantic Oil Producing Company. This type of installation for gas-lift purposes consists of the producing company providing the gas from its wells which the gasoline manufacturing company treats through its compression-type gasoline plants, each plant being equipped with a stabilizing fractionating tower, and from which the gas is returned to the producing company's leases under sufficient pressure to maintain the productivity of the wells under the gas-lift system. As the natural gas comes from the well it is taken to the near-by gasoline plant at a suction pressure of around 5 lb. and boosted through the plant, stripped of its gasoline content and returned to the wells operating under pressure-flow methods at 300 lb. pressure. The gas is metered into the compression plant, and again metered back to the producing company."

"The first plant of this type to start operating, known as 'Gilmore No. 7,' is located on the Atlantic Oil Producing Company's Fleet lease in Sec. 23-8-6. The plant takes gas from four wells and produced about 10,000 gal. of gasoline daily from a gas volume ranging around 3,500,000 to 4,000,000 cu. ft. A second combination gas-lift gasoline plant on the Atlantic's Grayson lease in Sec. 13-8-6 is producing around 8,000 gal. daily from gas derived from one well. The third plant of this type is on the Atlantic's Baker lease in Sec. 10-8-6."

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[1] REID, GEORGE, Gasoline Plant-Gas-lift Installation on Cooperative Basis, p. 31, *Oil Weekly*, Sept. 16, 1927.

"While the gas-lift gasoline plants operate on separate leases each about 1 mile from the central plant, all of the gasoline produced from the recycled gas used to flow the wells is transferred to central storage tanks at the No. 7 plant in Sec. 23-8-6."

"The operation features of these new plants may be of interest to gas-lift engineers. The gas is taken from the well at a suction pressure of 5 lb. and passed through the low side of the compressor machines. Each plant consists of three Clark Brothers 180 hp. twin engines direct connected to 15 by 20 in. and 7 by 20 in. compressor cylinders. Through this small installation plant No. 7 is handling about 3,500,000 to 4,000,000 cu. ft. of gas daily, which is used after treatment to flow four wells on the lease. When the gas is handled through the low-pressure side of the compressor it is discharged to a small scrubber tank and into the upper section of a two-section 10-in. condenser. From the bottom section of these condensers the low-pressure gas is discharged into the bottom of a bubble-type fractionating tower, 72 in. by 48 ft. in size. The gas then rises upward through the tower and passes out at the top, passes through a heat exchanger and into the high-pressure compressor cylinder where it is boosted to 300 lb. pressure. This cylinder discharges into small scrubbers, and into the top section of a five-section condenser. From the condenser the high-pressure gas is conducted to a 36 by 72 in. accumulator tank, where the gasoline accumulates and the gas is separated. The gas from the accumulator is piped through a back-pressure regulator to the manifolds, where it is distributed through various lines to the four wells. At the manifolds the gas is metered back to the producing company."

"Gasoline dropping out in the high-pressure accumulator tank is conducted into the top of the fractionating tower where its evaporation causes a low-temperature to prevail. The gasoline that condenses in the bottom of the fractionating tower is run to storage through the heat exchanger through which the cold gas from the top of the tower is also passed, thus cooling the finished gasoline going to storage."

"Each of the gas engines driving the compressors are equipped with fuel savers, which equipment injects the fuel gas in through the engine head after the burnt gases have been removed. This equipment is claimed by the operating company to provide for more power from the engines, and a fuel efficiency comparable with four-cycle engines."

"Each of these plants has one compressor machine arranged for use of the producing company when it desires higher pressure to start a well flowing, or what is known as 'breaking out.' The discharge piping on one of the high-pressure cylinders is so arranged that by closing one valve and opening another, after first unloading the low-pressure cylinder, a pressure as high as 1,200 lb. per square inch may be obtained. In this manner the plants are called upon to start the wells flowing after they are taken off production for any reason and to do so in a manner in which the continuous flowing of the other wells on the same lease will not be interrupted. With this arrangement with a gasoline manufacturing company, a producing company need not enter the business of making natural gasoline unless it so desires. Just what financial arrangements are necessary is not known, but in this instance the producing company is supplying gas for the extraction of gasoline and the gasoline company is supplying pressure and returning gas, for the operation of oil wells under pressure-flow methods."

"Among other interesting features of these compression plants is the water-cooling tower and the water-circulating equipment. The water pumps are located in a small building adjacent to the compression plant. A line shaft at one side of the engine house extends through to the pump house. This line shaft is driven from the flywheel of one of the Clark engines. For auxiliary purposes a 30 hp. Hercules gas engine located in the pump house is used to drive the line shaft when the larger engine is shut down for any reason. The water is circulated by two 3-in. double-suction Pennsylvania centrifugal pumps. These pumps are manifolded together so that when one is shut down, the other can circulate water over the engines as well as through the condensers. Ordinarily, one pump handles water from the bottom of the cooling tower pit through the condensers and to the sprays at the top of the cooling tower. The second pump is used to handle water from the hot pit or well, over a cooling tower placed above a 500-bbl. wooden tank, from which the water flows by gravity through the engine cooling jackets, and back into the hot well. A Pennsylvania air compressor to supply air for starting the engines, and a $1\frac{1}{2}$ k.w. electric generator are also driven from the main line shaft, which is employed to belt drive the centrifugal water pumps."

"The water-cooling tower is of company design. It is made of a frame of rough rig lumber and covered on the inside with galvanized corrugated iron, the sheets lapped like shingles, so that the water is retained on the inside of the tower. The corrugations are run horizontally, the struts being spaced so that a single standard length of corrugated iron reaches from one strut to the other. Doors are placed all around the bottom of the tower and are hinged at the bottom so that the tops open outward and downward. During summer weather the doors are kept open toward the direction from which the wind is blowing, which tends to create a current of air upward through the 30-ft. tower. During freezing weather all of the doors are kept tightly shut, which tends to reduce trouble in the tower from freezing. When strong winds are blowing the doors are adjusted, or part of the doors are closed, so that good cooling results are secured without loss of water."

"The water is sprayed downward from the top of the tower through $\frac{3}{4}$ in. Thompson double-spray nozzels, placed about 3 ft. apart. Downward spraying is practiced because the Gilmore engineers found that there was greater loss from winds carrying the water over when it was sprayed upwards."

"The other two Gilmore plants in the Bowlegs pool are virtually duplicates of the one just described, and function in the same manner."

"One of the advantages of building three plants, rather than one large centrally located compression plant, is that of a considerable saving in first cost. The smaller, compact units are quickly installed and placed in operation. Due to their design, with each separate section of the essential equipment being small and compact, the plants have a high salvage value and are portable, which will be of value when the company ceases flowing their wells by gas lift, and the plant equipment is needed in some other section of the field or in a different field. The company intends to move two of the plants, when necessary, leaving one plant as the permanent installation; laying vacuum lines from this plant to the other leases and returning residue gas to these leases through the lines now employed in transferring gasoline to the central storage plant. Each of the plants is designed so that it can be easily enlarged to take care of any increased supply of gas in its immediate vicinity."

"On the leases where the combination gas-lift-gasoline plants are now in operation, the Atlantic Oil Producing Company, has nine wells producing, four on the Baker lease, four on the Fleet and one on the Grayson. The company has other producing properties in the field which are not operated under this system. The leases in question, however, according to the late gages of the field, are producing from 2,000 to 2,500 bbl. of oil each. The gasoline company with three plants in operation is producing 8,000 gal. at one plant, about 10,000 at another, and around 4,000 gal. at the third. The company expects to produce from 20,000 to 22,000 gal. daily from its three 'gas-lift-gasoline' installations in the near future."

H. B. Bernard,[1] of the Sinclair Oil and Gas Company, in reviewing developments in natural gasoline manufacture published an article in which the following statement, which may be considered as a summary, appeared:

"Prior to the application of the gas lift to the production of crude petroleum, natural-gasoline plants of the absorption type had practically supplanted plants of the compression type due to the economic conditions involved and not due to the greater efficiency of the former, which is the common impression. In 1926 one of the major oil companies in the Browning pool near Madison, Kan., constructed a compression gasoline plant built for the primary purpose of extracting gasoline but with two secondary objects in view, the first of which was to put gas pressure back on the sand, and the second to produce oil from the relatively shallow wells (about 2,200 ft. deep) with the gas lift. This plant has been very successful and was the forerunner of the double application of compression gasoline plants."

"Early in the history of the Seminole field the first gasoline plants were built about August–September, 1926. These plants were universally of the absorption type, and made no provision for the production of high-pressure gas for flowing purposes. About 60 days later when several high-pressure compression plants using both air and gas were put in service, it was found that where gas was the medium compressed, gasoline was extracted, but as no final coolers were installed on the second stage, the gasoline production was very small. A short time later it became a more or less general practice to install an absorption-type unit on the discharge of the low-stage compressors to extract the gasoline, and this method is in more or less universal use in those plants constructed late in 1926 and early in 1927."

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[1] Bernard, H. B., Progress of the Natural-gasoline Industry for 1926–27, *Mech. Eng.*, p. 42, January, 1928.

"Considering that the condensing and cooling of a given amount of gasoline over a definite temperature range requires a given amount of condenser surface and with the view of eliminating absorbers, stills, and the numerous auxiliaries used in connection therewith, the Sinclair Oil and Gas Company in March, 1927, put in operation a gasoline plant, designed not only to efficiently extract gasoline under compression methods but to furnish high-pressure gas for producing crude petroleum by the gas lift. Shortly thereafter this plant was put in successful operation, and it has set a model type of construction and operation which will replace the high-compression type of plant utilizing absorption equipment for gasoline extraction. One of the principal problems presented in the construction of the two-purpose compression plant was the design of a system of controls to enable the operation of each individual well under the most favorable conditions and to permit the 'kicking' off of any well or wells without interference with other operations. This system was fully developed in July of 1927, and while it is undoubtedly capable of improvement, as the question now stands it is eminently satisfactory in operation both from the engineering and operating standpoints."

"To permit the operation at normal pressures (250 to 300 lb. per square inch) for gas lift in the Seminole field, and to provide for the same units to operate at 650 lb. per square inch for kicking off the wells, required the design of special cylinders, and the initial development of this equipment was found satisfactory. As the machinery is designed to operate fully loaded at the lower pressures, throttling devices on the suction for high-pressure operation have been resorted to."

"The application of the principle of compression for a two-fold purpose has resulted not only in economy of operation but has permitted the construction of large central plants as opposed to the construction of a number of smaller plants, with a corresponding further increase in operating efficiency and economy."

Costs.—The subject of costs of producing oil by the air-gas lift is a matter of greatest interest to all concerned, and, like every other cost proposition, each operator would like to know the other operators's costs but, as a rule, does not care to divulge his own costs. As a result, the few figures which have been issued are valuable but not nearly so useful as if the figures of each operator were available with data showing the causes of the differences.

Again, the subject of costs is treated differently by each operator in that the accounting systems consider different phases or elements in different ways. To ascertain the lifting cost per barrel, one operator will include every possible item pertaining in any way to the superintendence, overhead, installation, and operation of the system while the next operator may charge to the system only the installation and operating expenses. For costs to be comparable, they must be figured on a similar basis. And it might be stated here that the engineering force, with the assistance of the accounting force, is the logical personnel to determine upon what basis and what items should go into the accounting system for determining all pertinent costs of the air-gas lift installation and results.

It should first be mentioned that the costs of lifting oil as compared to the costs of lifting water are on a barrelage basis and not on the basis of the relative values of the material produced. It is wrong to assume that because of the lesser value of water, in general, compared to the value of oil, it is uneconomical to install a high-cost efficient plant for the production of water or that more leeway exists for an economical installation for lifting oil because of the greater value of this material. The lift application, as such, is merely a means of pumping or producing the desired material, if the material has value enough to make it profitable or necessary to produce it at all, the installation should be such as to produce the material at least total cost per unit.

The gas-lift systems in eliminating sucker rods, pumps, expensive pulling, cleaning and reinstalling tubing, and in eliminating the greater portion of maintenance costs, replacements, repairs, etc., show an important saving in costs, and successful installations where greater production, lower maintenance costs, and less grief are found immediately attract the attention of oil producers. This accounts for the present widespread interest in such recovery methods, and for the rapidity of developments and installations such as is noted at the present time.

The cost of the air-gas system indicates that it is to be used only where the producers feel reasonably sure that a good yield is to be obtained. While its greatest field has been in deep-well flowing, the more shallow territories have found it feasible where good bodies of sand and good saturation exist. The Braman field with production at 2,300 ft. is flowing wells economically with this system, and very recently a unit has been placed on a shallow field in Tulsa County, where the oil was being pumped from a depth of 800 ft. If favorable conditions are available, the shallow pools may turn to this method.

Even with efficient air or gas lifts for producing small wells the costs will be high. High-pressure air or gas lines will be required for each well so operated and separators for gathering the discharged gas will be necessary, at least for small groups of wells if not for individual wells.

The air-gas lift has conclusively demonstrated that it has two dominant points, it produces the oil quickly, and it produces the oil very economically, the production cost varying with the size of the well. Naturally, the smaller wells cannot be flowed as cheaply as the wells of larger yield, for the labor-cost item is practically constant and represents a heavier charge per barrel on the smaller wells. A figure of 50 bbl. per day has been set by one prominent engineer as the figure at which the ordinary type of equipment may profitably be used, and, according to this official, wells making less than 50 bbl. must be equipped with specially designed apparatus if they are to be flowed with a profit. At this point, the tapered tubing and the automatic control meter must be brought into use, as without them the expense of flowing is too great, chiefly on account of the compressor capacity which is required under the ordinary methods of air-gas lift operation.

In extreme cases, it is necessary to flow the wells by the gas- or air-lift method regardless of cost, as pumping troubles cannot be eliminated.

The gas- or air-lift method is very expensive, especially where the quantity of oil produced is small, the wells deep, and where the annular space between tubing and casing or walls of the hole is large. The quantity of air or gas for flowing under these conditions is necessarily large. The proper design and use of jet nipples or orifices in a small syphon line run in the tubing reduces, materially, the quantity of air needed.

Where gas must be purchased and its cost is greater than the reduction in lifting cost, which may be effected by its use in the gas lift, it is not economical to use this method of flowing. This is especially true where "thief" sands exist, into which part of the gas may escape. Gas, at a high price, may be used where it is impossible to pump wells on account of existing depths and crooked holes. Gas lift is the only method by which some deep wells with small production may be economically operated.

Wells operating on the gas lift seldom need cleaning out, due to the steady flow conditions that prevail. This fact has been instrumental in the development of a new and successful cleanout method, which involves the fundamental principles of the gas lift. The new method makes it possible to clean out deep pumping wells in approximately 5 to 10 per cent of the time previously required, with a saving of $1,500 to $3,000 per job.

Miller[1] made the following statements on the subject of installation costs:

"The cost of installing the process will depend largely upon the equipment already in use on the property. Usually gas traps, gage tanks, and gas lines to dispose of the gas from the traps to gasoline plants are already installed at a well to take care of the production while it is flowing. Such equipment can usually be used for the gas-lift process without many material changes. As the gas-lift method of flowing a well is simply another method of pumping a well and is seldom used until after a well has stopped flowing naturally or shortly before, it is but a question of which method of pumping will give the largest return on the capital invested. Wells on the gas lift usually produce more oil than would have been obtained in the same length of time by ordinary pumping methods and often the increase in gasoline recovered from the gas will pay all installation costs in 2 to 6 months."

"Gas-lift pumping stimulates production during the early life of a well. More oil is usually produced than could be raised by the ordinary oil-field plunger pump. Where at some wells from 300 to 600 bbl. of oil was the maximum obtainable by ordinary pumping methods, the gas lift has produced from 600 to 1,000 bbl. a day for a long period."

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[1] Miller, H. C., Mechanical Installations for Gas-lift Pumping, *Petroleum Development and Technology*, p. 85, 1927.

"For equipping wells to produce by the gas-lift method, there are necessary in addition to gas traps and gage tanks and other equipment of flowing wells:

"1. A compressor plant, including gas engines or electric motors, compressors, and accessories. If compressors are steam driven, steam boilers of sufficient capacity are required."

"2. Pipe lines for distributing the compressed gas to the wells."

"The costs of central-compressor plants vary with the types and amount of equipment installed and with the character of the installation and construction. From a limited amount of data the costs of complete compressor plants of several types of equipment have been obtained. The costs of several complete plants erected recently in California vary from $15 to $25 per 1,000 cu. ft. per day capacity. These costs include all compressor equipment, absorbers, piping, gages, buildings."

"Various sizes of compressors are used for flowing single wells. At some wells in California 8 × 4 × 8-in. straight-line tandem, two-stage compressors having a piston displacement of 113 cu. ft. and rated at 500 lb. per square inch working pressure are used. At other wells, 12 × 6 × 12-in. duplex, two-stage compressors with a piston displacement of 312 cu. ft. are used, while compressors intermediate in size between the above sizes are common in the California oil fields. The cost of one-unit compressor plants varies not only with the size of compressor installed but with the kind of motive power used to drive the compressor."

"The cost of an electric motor-driven compressor plant, including an 8 × 4 × 8-in. straight-line tandem, two-stage compressor, complete with electric motor, belt, foundation, piping, and labor charges is about $3,500; when a 10 × 4½ × 10-in. compressor is installed, the complete cost of the plant is about $4,500; and a 12 × 5 × 12-in. compressor installation with electric motor and accessories, including the cost of installing, is from $5,600 to $6,500."

"Where gas engines are used to drive the compressors, costs of complete plants have been considerably more than plants of similar capacity operated by electric motors. On one property the cost of a one-unit compressor plant consisting of a 10 × 4½ × 10-in. duplex, two-stage compressor, driven by a 60-hp. gas engine was $8,050. The cost includes concrete foundations for the compressor and gas engine, belt, meters, gages, piping, and all labor costs."

"A steam-driven $10\frac{1}{2} \times 5\frac{1}{2} \times 12$-in. compressor with 8-in. steam cylinders, a 75-hp. firebox boiler, concrete foundation for the compressor, necessary accessories, and labor charges cost on one property $6,600."

"Housing costs are not included in any of the above figures for one-unit compressor installations because they vary with the size of the building and the materials used in its construction. Also in many cases no building is constructed over the compressor plant."

"Portable electric motor-driven compressor units with a capacity of 250 cu. ft. displacement, mounted on 4-wheel trailers cost complete, ready to operate, from $5,000 to $6,500, depending upon the size of the machinery and the kind and make of trailer. The higher figure is for an Ingersoll-Rand type X.R.B. duplex, two-stage compressor with high- and low-pressure cylinder 12 × 12 and 6 × 12-in., respectively. The compressor is driven at 225 r.p.m. by 100-hp. electric motor. The compressor and motor, together with starting controller, resistance grids, and all necessary gages are mounted complete as a unit on a 4-wheel solid rubber-tired trailer. This outfit will easily handle one 4,000-ft. well making 1,000 bbl. or more of oil daily. When intake gas at pressures of 75 to 100 lb. per square inch is obtainable, this same outfit will handle two wells by using two 6 by 12-in. cylinders and operating the compressor as a single-stage unit."

Another writer stated that:

"The question of reliability of compressors is not brought into the picture for the reason that all compressors—anything that rotates and reciprocates—must at some time undergo repair and renewal and a well-designed plant, therefore, must have reserve units, whether electrically driven, or driven by gas, oil or steam engines."

"When sufficient reserve unit capacity is installed, continuity of operation becomes relatively an unimportant phase, although the equipment should be of the best type. There are disadvantages as well as advantages in each type of plant."

"Gas engines will not operate continuously, although the writer has had several non-stop runs of over 6 months; electric motors will not operate continuously, for the reason that lightning, field fires, and the like interfere with continuous transmission; steam engines will not operate continuously due to engine and boiler troubles, particularly boiler troubles."

"The installed cost of compressors ranges from $15 per cubic foot of free air delivered in the most favorable locations, using multicylinder engines and compressors, up to $20 per cubic foot of free air delivered in the larger weight, heavier gas engine driven types."

"For instance, a single unit of the latter type, with 15-in. low-pressure cylinder, 8-in. high-pressure cylinder, 20-in. stroke, two-stage, with 18-in. diameter twin gas-engine cylinders of 80 hp. each, costs $13,000 installed, complete; a second and successive units of the same type cost installed in the same plant about $11,000. With a displacement of 800 cu. ft. per minute and a volumetric efficiency of 80 per cent, the cost of air or gas from this machine, per cubic foot of delivered capacity, is $20."

"A 500-ft. displacement machine, or 400-ft. delivery capacity machine, of the two-stage belted type driven by a four-cylinder gas engine, costs installed, about $7,000. Conditions are variable, however, and there is no method of estimating the cost of plant without taking the local conditions into consideration."

As stated by Bond:[1]

"Development in the Seminole area was so rapid that only approximate costs were available. Roughly, the small units consisting of three 9½ × 4 × 10-in. compressors cost $4,500 to $5,000 each or $13,500 to $15,000 per well. Eighty horsepower units consisting of two 9¾ × 5 × 20-in. compressors cost from $10,000 to $12,000 each or $20,000 to $24,000 per well. The 165-hp. units consisting of one 15 × 7½ × 20-in. compressor cost $17,000 to $20,000 per well. These costs include everything in connection with installation of the plant up to the operating point."

"The cost of installing gas-lift systems in the Seminole field has varied with the type and size of equipment used. It is estimated that each well flowing under pressure is equipped with two compressors. The cost of piping gas to the well, oil to flow tanks, and gas back to the compressor plant is dependent upon the distance of the wells from the compression plant. Control instruments, meters, pressure gages, and other such items add to the cost of the installation according to the number and type of such instruments used. Some companies estimate the cost per well as much as $20,000, while others, flowing a larger number of wells from centralized plants have reduced this figure as low as $8,000 to $10,000. In comparison with this cost it is of interest to cite the practice of one large company operating gas lifts in the Torrance field of California, flowing wells at equivalent depths of the Seminole producers. This company installs one small compressor plant very close to the derrick and installing the entire system at a cost of less than $5,000 per well. The cost at Seminole as variously estimated by many companies will be somewhat reduced as other neighboring fields are developed, for as wells go off production and are abandoned or placed on pumping equipment, then this material, such as compressors, motors, pipe lines, fittings, control instruments, and so forth, will be transported from the old territory to the new area and used to flow additional wells until they, too, have reached the point where they are no longer sufficiently productive to warrant pressure flowing methods."

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[1] Bond, R. W., Mechanical Equipment of Air-gas Lifts in Oklahoma and Kansas, Exclusive of Seminole, *Petroleum Development and Technology*, p. 71, 1927.

The costs of several types of equipment have been considered, and a price of $24.50 or $25 per cubic foot per minute capacity may be termed "average" for the installation of an air-gas system. Costs fluctuate, but it is believed that this figure will represent the average cost. The most used size of compressor is the 250 cu. ft. per minute machine, and at this figure it will be observed that a cost of $6,125 will be required for the installation of one unit of this size. This price includes all expense connected with the equipment, buildings, fittings, pipes, charts, gages, and other recording instruments.

The operating costs are rather more subject to differing opinions and accounting systems than is the installation cost. The following extracts are from various sources:

The matter of cost is, of course, important relative to the installation of the gas lift. The cost of lifting oil by compressed gas varies from 2 to 15 cts. per barrel of oil, depending upon the efficiency of the gas lift. A difference of 10 or 12 cts. per barrel of oil in price is immediately noticed by an oil operator and the cost in production is as real to him as is the price of his product. The efficiency of gas-lift process, therefore, deserves more consideration than it has been given in some quarters.

It has been found that there is a wide variation between different operators and at different wells in the amount of gas used per barrel of oil lifted. Some of the efficient operations show oil being lifted with only slightly over 400 ft. of gas per barrel of oil. On the other hand, wells are being flowed that use as high as 3,000 ft. per barrel of oil.

The cost of compressing gas to 300 or 400 lb. varies from 3 to 5 cts. per 1,000 ft. of free gas and even up to 9 cts. This figure has been obtained from a number of sources and as a matter of fact is the basis of actual business transactions involving gas compression. The cost of lifting oil with compressed gas is thus determined.

Miller[1] states:

"It is difficult to determine the actual cost of pumping oil wells by the gas-lift method when compressed gas is supplied by a central compressor plant. Operators usually charge to pumping costs only the cost of compressing the gas supplied to the well, giving the well neither credit for the added gas returned, nor the additional amount of gasoline recovered. The generally accepted figure for the cost of compressing natural gas in large central compressor plants in California is from 3 to 5 cts. per 1,000 cu. ft. Plants with an output of 6,000,000 or more cu. ft. of gas per day estimate the cost of compressing gas at 3 cts. per 1,000 cu. ft. In smaller central plants, the proportionally greater overhead and labor charges usually tend to increase the compression cost to 5 to 7 or 8 cts. per 1,000 cu. ft. of gas compressed."

"The cost of lifting a barrel of oil varies with the volume of extraneous gas required to raise a barrel of oil to surface. On the basis of 3 cts. per 1,000 cu. ft. as the cost of compressing natural gas, some operators' lifting costs are not a great deal above 3 or 4 cts. per barrel. The average lifting cost by the gas-lift method of a large number of wells using gas from a central compressor plant is about 8 cts. per barrel of oil."

"One operator in the Southern California fields who operates 12 or more wells from a 5,000,000-cu. ft. daily capacity central compressor plant estimates that his company is flowing oil by the gas-lift method at from 5 to 7 cts. per barrel. In figuring this cost, he estimates the depreciation of the compressor plant at 20 per cent per year. In other words, the cost of the plant is charged off entirely within 5 years."

"The cost of operating one-unit compressor plants having a capacity of 400,000 or less cubic feet of gas per day varies from \$25 to \$40 per day, depending mainly upon the kind of motive power used. The lower figure is for a steam compressor, with the cost of operating an electrically driven compressor about midway between these two extremes. Using the above figures as a basis, the cost of compressing 1,000 cu. ft. of gas in a one-unit compressor plant varies from about 6 to 10 cts. The cost of lifting 1 bbl. of oil when one-unit compressor plants are used varies, therefore, from 6 to 20 or more cents with the average around 12 cts. per barrel."

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[1] Miller, H. C., Mechanical Installations for Gas-lift Pumping, *Petroleum Development and Technology*, p. 85, 1927.

"The lifting cost of 10 to 20° A.P.I. gravity at Cat Canyon, California, by the gas-lift method is about 14 cts. per barrel, whereas it previously averaged nearer 45 cts. per barrel when the wells were on the pump. Not only has the lifting cost been reduced, but the production has been materially increased since the wells were placed on the gas lift. The gravity of the oil has also been increased about 2° A.P.I. gravity, principally because the gas lift has been instrumental in decreasing the sand cut from about 30 to 3 per cent."

Shaw[1] stated:

"When small wells are operated by gas lift the lifting costs become a matter of great importance. If the small electric-driven compressor that was employed for high pressures be employed for small low-pressure wells, the cost per 1,000 cu. ft. of compressed air or gas will probably reach 7 or 8 cts. and at 10,000 cu. ft. per barrel the cost would reach 70 to 80 cts. with no allowance for interest or depreciation. On the other hand, gas can be compressed in a compressor direct driven from a gas engine at a cost of 3 to 4 cts. per 1,000 cu. ft. and the lifting cost then becomes 30 to 40 cts. per barrel which is considerably lower than would be the cost of a well on the beam, where frequent stoppages are caused by rod breakage, leaky valves, etc."

"We have operated a small well by compressor for 60 days without loss of production for a single day. If now we consider the cost of lifting oil in a well of 100 to 200 bbl. per day, total depth of 4,000 ft. operated by air lift and equipped with tapered tubing of proper design, we would have a gas input consumption of about 2,500 cu. ft. per barrel, which at 3 to 4 cts. per 1,000 cu. ft. would be 7½ to 10 cts. per barrel, and there would be very infrequent loss of production due to stoppages."

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[1] SHAW, S. F., Air-gas Lift Practice in the Seminole Field, *Petroleum Development and Technology*, p. 100, 1927.

There is no difference in compressing gas for blowing wells or for gasoline plant manufacture, in principle. Working pressures for well work, however, are higher, and the requirement as to pressure varies materially in the same well.

The horsepower requirement for various pressures is as follows:

Delivery pressure, pounds	Horsepower required to compress air in two stages, per 100 cu. ft.
200	24.1
300	28.3
400	31.7
500	34.2
750	36.0
1,000	38.3

Of course, two-stage compression for the higher pressures is not strictly good engineering, but the balancing of cost and maintenance of additional cylinders against fuel costs disclose the cheaper compression ratios. In other words, high power costs call for dividing the compression ratios carefully, to secure the highest compression efficiency, while, with lower fuel cost, the compression efficiency need not be so high, for the additional machines required to subdivide the compressions set up fixed charges that may offset the gain of higher efficiency. This is true in many power installations, that the very highest mechanical and thermal efficiency are not always the cheapest in the end, rather a high overall efficiency, all charges included.

The cost of generating 1 hp. varies with fuel cost, mainly. For rough estimating purposes, power costs per brake horsepower per hour are about as follows:

Gas engines, ¼ ct.
Oil engines, 1 ct.
Steam-boiler engines, 2½ cts.
Electric power from central stations, 1 ct.

An article by C. P. Clark[1] was published on the relative costs of gas engine and electrical motor driven compressing units. It is quoted here in full, not so much for the results of the comparisons as made, for it is believed that the electrical application would show in practice a little better than stated here, but for the presented detailed analysis of the subject:

[1] Clark, C. P., Operating Costs of Gas Engines *vs.* Motor Driven Compressors, *Oil Weekly*, p. 89, Dec. 23, 1927.

"In gathering data for this paper it was quite apparent that, because of the rapid development and changes in the air-gas lift method of pumping oil, costs and estimates must be of a general character."

"There seems to be quite a diversity of opinion as regards costs. For instance, S. F. Shaw, in an article on Air-gas Lift Practice in the Seminole, sets the price per 1,000 ft. of air of direct gas engine driven compressors at 3 to 4 cts., and the electrically motor driven compressors at 7 to 8 cts. It is to be assumed that he is quoting from his experience with the Carter Oil Company. The Indian Territory Illuminating Oil Company estimate, roughly, 8½ cts. per thousand for electrically driven units and 5 cts. a thousand for gas engine driven compressors, where their fuel cost is 25 cts. a thousand."

"In order to arrive at some basis of comparison, estimated costs from Seminole field experience have been compiled of the two types of plants. These plants are of the average size and of the same capacity, compressing air from 0 to 300 lb."

"SIX UNIT DIRECT DRIVEN GAS ENGINE PLANT

Interest on $51,000 at 6 per cent	$ 8.37
Depreciation at 10 per cent	13.90
Repairs, 2 per cent engine cost	1.65
Wages—operators and oilers	25.00
Oil and waste	3.90
Fuel at $1.25 per 1,000	32.40
	$85.22

Total capacity, 2,700,000 cu. ft. per 24 hr.
Cost per 1,000 cu. ft., $0.0318.

NINE UNIT MOTOR DRIVEN COMPRESSOR PLANT

Interest on $45,000 at 6 per cent	$ 7.40
Depreciation at 10 per cent	12.30
Repairs at 1 per cent compressor cost	1.20
Labor—3 operators	15.00
Oil and waste	1.90
Current at $0.0117 kw. and 60 kw. per hr	157.20
	$189.00

Total capacity 2,700,000 cu. ft. per 24 hr.
Cost per 1,000 cu. ft., $0.07"

"The cost per unit of the electric driven plant installed was estimated at $5,000. This includes buildings, necessary piping, auxiliary equipment, etc. The cost for installing a 90 hp. tandem unit, including buildings, foundation, necessary piping, auxiliary equipment etc., was estimated at $8,500. The capacity of the motor driven unit was 300,000 cu. ft. per 24 hr., and of the gas engine driven unit 450,000 cu. ft."

"In arriving at the labor cost only the salaries of the actual operators have been included. The motor driven plant requires one operator per 8-hr. shift at $150 per month. The gas engine driven plant requires one operator and one oiler per 8-hr. shift; the operator is paid $150 per month and oiler $100 per month. The repair cost was based on 2 per cent of the cost of the compressor equipment for the gas engine plant, and 1 per cent for the motor driven plant. Reducing the above costs to the basis of 1,000 cu. ft. of gas or air compressed, the cost for electric operation is 7 cts. while with gas engine operation it is 3.18 cts."

"In the above figures, please note that the fuel bill in the gas engine plant is the largest item and has been charged at 25 cts. per 1,000. While there were some plants in the Seminole field paying this rate, in the majority of cases no charge was being made for the fuel, in fact, it was not even being metered. Deducting this item makes the actual cost 1.96 cts. per 1,000 for the air gas. In the future it is safe to predict that there will not be the excessive and careless waste of gas as occurred in the Seminole field. The cost of the current was based on actual figures in the field, namely, $16.80 per unit. This is a very low figure; estimating the power at 60 kw., the charge per kilowatt would be 1.17 cts. per kilowatt-hour."

"While it seems to be generally accepted that there is no question as to the considerable saving in operating costs, there seems to be quite a preference among some of the operators for electrically driven units to handle the flush production. Mr. Shaw has stated in his paper that he prefers the electrically driven unit owing to the flexibility and dependability at the early stage of the air-gas lift operation. After the pressures decline to a low point and it is desired to operate the wells by gas rather than air, he then prefers the gas engine driven compressor because of the considerably lower operating cost."

"Where the compressor is driven by a 100 hp. motor, it undoubtedly has greater flexibility in being able to operate at nearly normal suction pressure and compress to 700 or 800 lb. or whatever is necessary to 'kick' the well off. Under normal operating pressures, the gas engine is much more flexible as its speed may be controlled by the governor, while with the motor driven unit, because of the constant-speed characteristics of the motor, it is not practicable to vary the speed. Mr. Shaw's expressed feeling of doubt as to the dependability of the gas engine has probably come from his experience in the Seminole field. It should be kept in mind that the production departments of the large oil companies were required to install a large number of a new type of machine with little experience and along with this build up a new operating force. Naturally, through lack of training, some grief must have been experienced. In the past, the natural gasoline manufacturers went through this same experience but today there are hundreds of engines running on which an operating efficiency between 99 and 100 per cent over a year's time is not considered unusual. There is also the unfortunate situation that because of the considerable size of several of the oil companies, the natural gasoline and production departments operate quite independently of each other. After the production departments become familiar with this type of machine, this phase of the situation will undoubtedly right itself."

"With the direct gas engine driven plant, where troubles do occur, the operator in practically all cases can take care of the trouble without having to find a superior, while with the motor driven plant it is always necessary to hunt the electrician and quite often trouble in an electrically driven plant shuts down the whole system. Where trouble occurs with the direct gas engine driven unit, it is possible, by speeding up the other units, to help take the load, but with the electrically driven plant it is only possible to take up the load of the down unit by increasing the suction pressure, which in most cases is not possible."

"Where both types of units are to be used for the air-gas lift method, it would seem there must be considerable economic waste in switching from one type of unit to the other and in many cases there must, of necessity, be duplication of plants."

"As the wells fall off in production the air-gas ratio naturally increases so that even with the most efficient air-lift method, the cost per barrel in many cases will run over that of operating on the beam. Mr. Shaw states in his article that they have pumped a 10-bbl. well with 10,000 ft. of gas. With electric operation this would be approximately 70 cts. a barrel, with gas engine operation about 32 cts. which is considerably below the cost of operating on beam."

"There is also a coming phase of the air-gas lift production which has been considered but has, as yet, had very little field trial. That is, the further recovery of oil in the Seminole field by repressuring the sand. One large operator has installed his plants with this in view. If these were to be operated by electricity, the cost would make economical production of oil out of the question."

Brundred[1] stated in this regard:

"In any discussion of costs, naturally, the price paid for natural gas, fuel oil, or electric power must be known in advance before actual cost of compression can be determined."

"As a guide only, the following table was prepared using the different unit costs of power as shown in the body of the table and contemplates amortizing the entire investment of a complete gas-lift station for operating the lease from a central control station in a period of 5 years, including therein all such normal charges as operating, interest, and depreciation."

TABLE XXXVIII.—COST OF COMPRESSION

Kind of plant used	Cost of fuel	Cost per 1,000 ft., cents
Gas engine driven compressors.......	10 cts. per 1,000 cu. ft.	2
Oil engine driven compressors.......	$2 per barrel	3½
Electric driven compressors.........	2 cts. per kilowatt-hour	7
Steam driven compressors...........	10 cts. per 1,000 cu. ft.	7

"The above table was prepared on the basis of a 10-well property requiring 2,500,000 cu. ft. of circulated gas per day, under average operating conditions of atmospheric intake and 300 lb. discharge."

"In computing the cost of lifting 1 bbl. of oil as shown below, the data contained in Table XXXVIII were used. Added thereto are additional columns for costs based upon data contained in Table XXXVIII*a*."

"It must be noted, however, that the cost of compression, although the major part of the cost of raising a barrel of oil, is not the final cost. Therefore, to the cost of compression in each case there has been added 2 cts. per 1,000 cu. ft. to take care of all such items as lease labor and supplies normally charged to 'lifting cost' in the average oil field. Experience has shown that this is a reasonable charge on a medium-sized property, completely operated by the gas lift."

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[1] BRUNDRED, L. L., Practical Production of Oil by Gas Lift, *Oil Weekly*, Nov. 11, 18, 25, 1927.

"To be sure, it is not generally realized that although the original cost of installation is generally higher than the average standard rig or band wheel power, the cost of operating the property is so much less that, over a period of five years, the additional investment is paid out of the profits derived from cheaper operating."

TABLE XXXVIII*a*

Barrels	Cubic feet per barrel	Unit cost, gas engine driven compressors, $0.04	Unit cost, oil engine driven compressors, $0.055	Unit cost, electric driven compressors, $0.09	Unit cost, steam driven compressors $0.09
4,000	250	0.010	0.014	0.022	0.022
2,000	400	0.016	0.025	0.036	0.036
1,000	700	0.028	0.039	0.063	0.063
700	900	0.036	0.049	0.081	0.081
500	1,000	0.040	0.055	0.090	0.090
300	1,300	0.052	0.072	0.107	0.107
150	1,500	0.060	0.083	0.135	0.135
100	1,800	0.072	0.100	0.152	0.152
50	2,400	0.096	0.132	0.216	0.216
25	3,000	0.120	0.165	0.270	0.270
10	5,000	0.200	0.275	0.450	0.450

"Although the cost of erecting a standard rig to pump each well remains the same regardless of whether it be a large or small well, this does not hold in the case of gas-lift plants. The cost of installation of such a plant is based solely on the number of barrels to be lifted and not on a per well basis."

"It is to be noted that additional revenue from increased oil and gasoline sales, almost universally found on properties operated by gas-lift, has not been used to reduce the lifting cost per barrel as shown in the table above."

As to the cost, while the actual figures for the various companies varied with their accounting methods, some figures on the lift in Seminole, where between 75 and 78 per cent of the oil is being produced by means of the air-gas lift, were cited by Hollis P. Porter,[1] Gypsy Oil Company, as being fairly representative of costs on this type of production. In the plants in his discussion the units total over 150. Each unit consists of a high-speed 4-cylinder gas engine close belted to a tandem two-stage compressor with a free air capacity of 250,000 cu. ft. per day. There are an average of three units per well, the wells having a daily average production during 1927 or 152.57 bbl.

"The cost per day to flow one well during the same time was $29.94, or a lifting cost of 21 cts. per barrel. This figure includes all installation charges, operating expense, labor, repairs, fuel gas at 25 cts. per 1,000 cu. ft. and, in addition, the amortization of the investment over a 2-year period. It does not include the cost of the leases, drilling expense, or general overhead. It was felt that this was not excessive for oil produced from wells 4,200 ft. deep."

Notes on Design.—The design of a air-gas lift installation on paper alone is a rather hazardous undertaking due to the great number of variables that enter the problem. It is not intended in this section to give the details of a system of design, for practically everybody that attempts such work has or evolves his own system, but extracts from various writers and comments will be given mainly in an effort to enumerate some of the considerations which enter into the design work.

Some of the factors entering into the problem are covered by Pierce and Lewis[2] as follows:

"In examining a well in a pool on which the gas lift has not been tried or experience factors set up, the data necessary to determine whether a gas lift would be beneficial are:

A. General:

1. Depth of sand.
2. Nature of sand or producing formation.
3. If the well flows or had ever flowed naturally, and how long (see Specific).

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[1] Porter, H. B., figures presented at Feb. 2, 1928, meeting of Mid-continent Section, A.I.M.M.E., and reported in the *Nat. Petroleum News*, p. 47, Feb. 8, 1928.

[2] Pierce, H. R., and J. O. Lewis, Principles of Air-gas Lift As Applied to Oil Production, *Petroleum Development and Technology*, p. 19, 1927.

4. Size of hole and how cased.

5. Whether oil was produced by gas or water drive or the relation of each as near as possible, if both water and gas were the energy expelling the oil.

6. The initial production and relative rate of decline of oil, gas, and water, if any.

7. Present rate of production as compared to other wells in pool similarly located and drilled.

B. Specific Information:

1. If the well were flowing:

a. Rock pressure of shut-in well.

b. Nature of flow; that is, steady or by heads, etc.

c. Quantity of oil, gas, and water, if any, produced by well against different back pressure held on the head of the well; three tests of this nature are desirable, and the data worked up in the forms hereinafter described.

2. If the well is not flowing:

The quantity of oil and gas that the sand will deliver should be plotted against the head in feet of fluid above the top of the sand; that is, the oil level should be pumped, swabbed, or bailed down to three or more depths, and the quantity of oil and gas produced from these various places tabulated and plotted against pressure head of fluid above the sand, which pressure may be deduced from head and density of column, taking account of gas quantity in the column, gravities of gas, and liquids, etc."

G. B. Parsons,[1] of the Magnolia Petroleum Company, stated: "Factors to be determined before tubing is run:

1. Daily oil production while pumping.
2. Gravity of oil.
3. Emulsion, in percent.
4. Water produced, barrels per day.
5. Casing-head gas, 1,000 cu. ft. per day.
6. Casing-head gas per barrel of oil produced.
7. Shut-in pressure of casing-head gas at well head.
8. Pressure on sand or 'rock pressure.' (Shut-in pressure of casing-head gas plus pressure due to weight of column of compressed gas plus pressure due to column of fluid in hole.)
9. Internal diameter of casing.
10. Internal diameter of open hole.
11. Total depth of well.
12. Depth of oil sand.
13. Condition of hole.
14. Casing point.
15. Volume of extraneous gas available.
16. Pressure of extraneous gas available.
17. Rate of build-up of fluid against time intervals—this is necessary if an attempt is made to increase production based on isothermal expansion.

[1] Parsons, G. B., Handling of a Small Settled Producing Well with Gas Lift, *Oil Weekly*, p. 54, Aug. 19, 1927.

18. Atmospheric pressure.
19. Oil level, or daily displacement of fluid in 24 hr.
20. Difference in feet between fluid level in casing under shut-in pressure and in tubing open to atmosphere at top.
21. Jet level—should be just above fluid level in casing.
22. Size and number of jets—based on theoretical working pressure at jet level and volume of gas required per barrel of oil."

The problem of design at the best consists of adapting the form, size, and amount of the material to be used to the needs of a proposed installation as near as may be; then finding from experience with that installation what alteration may be necessary to improve its operation.

The following factors which should be considered in design are quoted from an article by Foran:[1]

"There are many factors which control the ultimate production of oil and gas from a producing formation and the rate at which this production is obtained from any of the producing wells in the formation. The most important of these, and the one over which the greatest control can be exercised, is the differential pressure existing between the formation and the well bore. In producing any well by means of the gas lift, it may be possible to change the flow tubing in a number of ways or vary the volume of circulating gas or air used for flowing the well, but if these operations, regardless of their magnitude, do not change the differential pressure between the producing sand and the well bore, they will in no way change the production of the well. If this statement be accepted as a fact, then all gas- or air-lift installations should be designed with but one object in view, namely, a means by which we can economically control very wide ranges of differential pressures between the formation and the well bore."

"In gas-lift production from any given formation, there are four major factors which govern the magnitude of the differential. They are: (1) the depth of the well; (2) type and size of flow tubing; (3) volume of the circulating air or gas; and (4) physical properties of the oil-gas mixture after it has reached the well."

"The first of these factors mentioned is uncontrollable and does not vary. The other three are controllable within certain limits. The degree to which the last three factors can be controlled will entirely govern the length of lift of the well while on the lift, the lifting cost, and the daily production. It will also govern to some extent the ultimate production from the wells or leases producing by this method."

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[1] Foran, E. V., Mechanical Installation of the Gas Lift in Texas Outside the Gulf Coast Region, *Petroleum Development and Technology*, p. 59, 1927.

"Gas-lift practice in Texas, other than the Gulf coast region, is confined to wells whose depths vary from 800 to 3,200 ft. There are some wells of less than 800 ft. on gas lift but they are unimportant and will not be discussed in this paper. Since the depth of a gas-lift well is a vital factor affecting the formational differential and cannot be changed, its influence, therefore, must be compensated through a variation of the remaining three factors."

"In analyzing the present gas-lift practice in Texas it appears that every installation is of a somewhat different type. The trend of operations at the present time seems to be toward those installations which are capable of lifting a barrel of oil to the surface with the lowest gross gas-oil ratio. At first thought, a low gross gas-oil ratio would seem to be highly desirable, and should be indicative of the efficiency of the installation, but if the gas-lift method of production is to occupy a prominent position in the production life of a well or lease, the measure of efficiency must be reduced to lifting costs per barrel in dollars and cents and the effect on ultimate production rather than the control of the gross gas-oil ratio."

"Mechanically the gas lift is operating at maximum efficiency when it produces the most oil with the least amount of gas. It may be, however, that increase in volume of gas supplied will result in a decrease of gas production from the well itself and, from the standpoint of ultimate yield, this would in most cases be preferable to the mechanically more efficient condition."

"Moreover, an increase in gas volume may substantially increase the oil production and although that increase may be out of proportion to the increased production, the latter may yet be sufficient to justify the poorer efficiency. Cost per barrel produced is the determining factor rather than the mechanical efficiency."

"The pressure exerted on the face of a producing sand of a gas-lift well is equal to the pressure due to the effective weight of the flowing column of the liquid gas mixture plus the pressure required to overcome the frictional resistance of this mixture to flow."

"This pressure may be reduced through increased aeration of the fluid mixture provided the tubing has sufficient cross-sectional area to accommodate the increased flow of gas without requiring a high velocity. Under these conditions the loss in weight of the flowing column due to aeration is much greater than the increase in friction caused by the greater volume of gas flowing with the oil. The result is an overall drop in pressure at the bottom of the tubing. This constitutes the principal advantage of large tubing over small tubing in cases where the rock pressure is subnormal."

"In the use of large flow tubing it may be reasoned that the velocity of the gas in the lower portion of the tubing might be so slow, due to the higher pressure of the gas in this portion, that it might not disseminate the oil properly and thus cause heading and 'slippage.' This is quite likely to happen unless the lower portion of the tubing is reduced to such a size that the initial velocity of the gas-oil mixture will produce a steady flow. The length of the reduced portion need not be more than 10 or 15 per cent of the total length of the flow string."

"It is apparent that if the maximum size tubing that can be used in a well is very efficient for low-pressure work it means that one tubing installation is all that is necessary during the gas-lift life of the well. This is explained by reason of the fact that when a well is larger than 1,000 bbl. daily it may be flowed by two-stage compression at low gross ratios, and on falling below 1,000 bbl. daily, the high-pressure cylinders of the compressors may be replaced by low-pressure cylinders and low-pressure flowing accomplished. Since the surface flow lines and trap installations have been given prominent mention in describing gas-lift operations during the past year they will not be discussed other than to say that the trap should be as close as possible to the well and the lead lines be equipped with long radius ells or bends wherever a change in the direction of flow is required. If recirculation of the wet gas is desired, the gas line from the trap to the compressor intake should be large enough to carry the gas with a minimum of frictional losses."

"As previously stated, if the flow tubing is of sufficient cross-sectional area, the volume of circulating gas may be increased until the working pressure against the face of the producing sand has declined to the point where it requires the least volume of formational gas per barrel of oil produced. If the gas is separated in the trap under pressure, it may be returned to the compressor at pressures above atmospheric and result in a larger volume of circulating gas and a more efficient flowing condition. With any given tubing sizes and arrangement, the volume of circulating gas required to do the best work can be quickly determined by simply increasing or decreasing the compressor output and noting the results."

"Immediately after the oil-gas mixture from the formation enters the well it comes in contact with additional gas that may or may not be saturated with the volatile hydrocarbon vapors. If the input gas or air is not saturated, it immediately absorbs the gasoline vapors from the oil and results in a progressively higher viscosity of the oil as the pressure drops on approaching the surface. It also increases the rate of paraffin deposition on approaching the surface. When wet gas is recirculated by means of single-stage compression and all of the vapors and condensate allowed to return to the well, these conditions cannot happen. It is, therefore, well to state at this time that gasoline plants which take the gasoline out of the recirculated gas are a serious detriment to gas-lift operations. They should be permitted to take the gasoline out of only that portion of the total wet-gas production which escapes to the air. A single-stage compression plant which returns all vapors and condensate to the well accomplishes the same work as the gasoline plant without the first cost or maintenance of the gasoline plant. The recirculation of the wet gas merely stops the separation of gasoline from the oil and delivers the oil to the tanks at the maximum gravity possible."

D. K. Hutchcraft[1] stated:

"There are many theories prevalent pertaining to the gas lift at this time which conflict with the principles of the air lift as applied to water. My conclusions are that every principle involved in the water lift is found in the gas lift; both follow the laws governing wells flowing naturally. The main difference between flowing water and oil is the presence of gas in the oil well which assists flowing and the necessity in a water lift to have high efficiency as water sells for only a few cents a barrel. It is necessary for this efficiency to maintain a high submergence. But in flowing oil the value per barrel is much greater, hence operating costs of maximum efficiency are not so important and much lower submergence can be used."

"The principles of air or gas lift I divide into three parts. First comes the air or gas lift where submergence is the main factor. This principle corresponds to a well flowing naturally with normal oil-gas ratio. In this division every principle involved in the water lift as generally used is found in the gas lift. This holds true so long as the working pressure is reasonably high, so that it is not necessary to depend on velocity. In this type of installation the highest efficiency can be obtained and the oil-gas ratio will be the lowest for the particular well."

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[1] Hutchcraft, D. K., Principles of Air-gas Lift in Oil Production, *Nat. Petroleum News*, p. 284, Sept. 21, 1927.

"This condition usually is found in flush fields where the oil-gas ratio is low. Seminole is a very good example of these conditions, it being comparatively easy to make an installation. The efficiency is at its maximum, requiring very little engineering skill to make an installation that is satisfactory regardless of whether the producer has used every precaution in designing his plant to obtain the highest efficiency and the greatest economy of operation."

"In my opinion, the operation and maintenance costs can be materially reduced by using a standard direct connected gas engine driven compressor. Under this classification the most efficient installation is where the velocity is held down to a minimum. The normal capacity of a gas lift can be obtained by the following formula:

$$C = \frac{P \times 2.31}{L + Y} \times AC_1.$$

C is normal capacity; P is absolute pressure in pounds (at the nozzle or the footpiece); L is length of discharge pipe from point air or gas is injected in the bottom of the well or from the nozzle of the footpiece to point of discharge; Y is back pressure in feet, referring to water; A is area of discharge; C_1 is the constant depending on the gravity of the fluid being lifted."

"It has been found advantageous in some cases to pinch in the discharge which is generally termed 'holding back pressure' on the gas lift, but by the properly designed installation, no back pressure will be required, consequently a much higher overall efficiency can be obtained. In a number of instances where sheet water has been encountered below the oil sand, it has been found that by putting in the tubing at the bottom of the well, the water increases materially, owing to the coning effect. This has been overcome to a great extent in a number of instances by raising the tubing."

"Inasmuch as the normal capacity is increased or decreased according to the working pressure, it will be found that by properly designing the flow lines so that the producer can take advantage of the maximum operating pressure, the same results will be obtained as far as back pressure or differential of pressure is concerned, and the number of barrels per day will remain constant regardless of the location of the tubing, but with a greater efficiency. Consequently, a lower cost per barrel can be obtained by changing the tubing to the proper size. The back pressure will vary as the total number of barrels per day vary."

"Better results will be gained when the tubing is located as low in the well as possible, generally just above the oil sand. The results obtained will be a lower oil-gas ratio, less horsepower per barrel lifted even though the working pressure may be materially increased. Great care should be taken in designing an air- or gas-lift plant. All compressors, pipes, and fittings should be designed with a conservative factor of safety so that the operator can avoid accidents which are bound to occur unless great care is taken."

"Seminole is now passing from the first principle to the second principle involved, the velocity lift where the actual working pressure or submergence is so low that it requires very high velocity. This principle is similar to a well making a great deal of gas and spraying oil naturally. In this case, it is readily seen that the amount of gas or air required to lift a barrel of oil will be high and, consequently, the efficiency low. An installation of this type is justifiable where the proper care in designing the compression plant has been used to obtain the lowest cost possible per million feet of gas compressed. It eliminates the excessive maintenance found in trying to pump wells, especially deep ones, with the plunger type pump. In many instances the efficiency has been greatly increased where these conditions exist by flowing by heads. This changes the principle back to the one involved in the first division until the head is blown off and the air or gas starts to break through."

"The third principle involves the use of a combination displacement and gas lift, where the well is operated intermittently. The design of this installation calls for the proper size flow line with the properly designed orifice in it above the oil level so that sufficient pressure may be obtained on the fluid in the well to force it up to the discharge pipe where it is mixed with the air or gas passing through the orifice. This type of installation has been used very successfully, modifications being made to meet well conditions."

"Nothing is needed in a well where the sand is tight with the exception of a properly designed discharge. However, where loose sand is encountered it is necessary to have a suitable chamber surrounding the discharge pipe with the properly designed foot valve for the oil to enter. This of course is an intermittent flow design, it being perfected by I. S. Dunn who has put in a number of this type installation, especially in West Virginia and in Pennsylvania."

"There has been much discussion of the relative advantages of using air or residue gas. It is my personal opinion that residue gas should be used at all times possible, there being practically no corrosive effect when residue gas is used unless air is present in this gas. Whereas when air is used frequently a good deal of trouble is caused by corrosion, especially when water is present."

"There have been several instances reported where the production per 1,000 ft. of air was much greater than when residue gas was used. These results were obtained from the same well in one instance. Using the same number of cubic feet of gas as air, the production was reduced almost one-half. However, from data obtained from other wells the difference, if any, was so slight as not to be noticeable. The use of the air or gas lift has been very extensive in scope in the greater Seminole district. On Aug. 25, 1927, there were 730 producing wells, producing approximately 437,226 bbl. of oil that day, of which 337 wells were flowing by the air- or gas-lift method, 107 were flowing naturally, 120 on the pump, 80 on the swab, 65 not producing. It is my opinion that without gas-lift, production would not have exceeded 275,000 bbl."

"In summing up the many advantages of using compressed air or gas in the production of oil, I feel that within a short time the oil fraternity will as a whole recognize that it is one of the principal factors in oil production; that when a new field has been brought in the operator will design his plant so that he can continue to operate it with the maximum efficiency during each period above mentioned; that he will bear in mind the application of air or gas being put back into the sand. This will be done as soon as the rock pressure has diminished to a point where it is practical to start restoring the pressure. Several of the larger producers in the Seminole pool are taking steps at the present time to carry out a similar program. In fact, one of the major companies in buying original air- or gas-lift installations for Seminole had this in mind."

"It is my opinion that most of the direct connected gas engine driven compressors in Seminole will be used for restoring the pressure in a large part of that field inasmuch as the lowest operating cost possible including power cost is obtained by this type of unit. A number of the operators have previously put in installations for restoring pressure on the sand to increase production, whereas in Seminole this application would be to maintain a reasonably high production."

"Each individual well has proven a distinct problem in itself when the gas-lift system has been installed to flow it. In former days before the technology and engineering problems of the system were understood it was often very difficult to duplicate results secured on a given well, when its neighbor was submitted to artificial flow methods. It is well known that many companies installed lift systems in late years which were successful in one district, and when the same companies installed the same material, system, and devices, and employed the identical machinery and pressures in other pools, that their second venture was distinctly unsuccessful. Such results added additional conflicting data to the ever growing mass of information available regarding artificial flow methods. The answer of course is simply, 'they did not have the same oil wells.'"

"The problem presented in gas-lift design is, first, to so place the tubing as to secure a maximum yield of oil from the productive sand; second, to make use of a size of tubing that will give the necessary capacity, offering a minimum resistance to flow of the fluids and yet permitting of a minimum of gas slippage; third, to employ a gas pressure which will be as low as possible for the necessary lift; and fourth, to operate with as small a gas volume as is consistent with proper lift efficiency. Inasmuch as these factors are mutually interrelated, it is only possible to approach the problem by 'cut-and-try' methods, varying each factor in turn until the best combination is secured."

As stated by Shaw in one of his papers:

"In the oil fields practically all air and gas lifts have been designed by previous experience or by guess, and take little account of efficiency. If the lift as first installed in a well produces more oil than can be pumped on the beam the designer or operator concludes that it is successful; if it fails, the lift is pronounced a failure so far as that particular well is concerned; and yet either of these instances may be far from obtaining the results that could be obtained by basing the design on a scientific knowledge of air-lift principles. Nearly all oil fields differ among themselves in conditions, and even in wells of the same field marked differences in conditions usually exist. Unless these conditions are properly considered when making a design, there is little likelihood of obtaining efficient results. A design of air lift operating successfully in one field may easily operate unsuccessfully in another field."

"The slightest change in diameter or length of pipe makes surprising changes in results. A change of ⅛ in. in diameter, or of 50 ft. in length, will make a marked change in capacity and efficiency."

"The essential parts of an air lift or gas lift are as follows:

1. Footpiece, or 'flow device,' or pump, which is placed on the lower end of the flow tubing.
2. Flow tubing, or eductor, extending from the footpiece to the top of the well.
3. Separator, or headpiece, at the top of the well, at the upper end of the eductor."

"Many kinds of footpieces, or 'flow devices,' are found on the market, most of which are of poor design. Footpieces of standardized design can be made for various capacities for work in shafts or in large openings, but in oil wells the limitation of casing diameters is such that the writer finds it advisable to make a design to fit each set of conditions."

"To secure the best results for a given set of conditions, the utmost care must be taken in designing the flow tubing. Poor designs usually result in the well flowing by 'heads,' and as nearly all oil wells flow by heads in which air lifts are employed, it can be taken for granted that nearly all oil well air lifts are inefficient."

"Separators are necessary to remove the air and gas from the liquid. A simple design can be employed for air lifts where no effort need be made to conserve the gas. If it be desired to conserve the gas for fuel or to use it over again in closed circuit through a compressor, it is desirable to employ a separator of substantial character."

"Rule of thumb, run-an-air-line-down-and-turn-the-air-loose, methods are sure to result in the size of compressor plants being far greater, and the investment far greater, together with higher lifting costs, than where competent, careful, observant, analytical engineers handle not only plant, but well operations. Observing the field in this wise, the cut-and-try method is seen to be the most prevalent, and the result is that there are now operating long rows of compressors that will depreciate greatly when shut down after the flush production is off. While the majority of installations are suitable for gasoline plant work, and many are now so being used, still there will be capacity far in excess of requirements for this purpose."

On the Gulf Coast, similar long rows of compressors, with no duty available for them but blowing wells for no natural gasoline is made there, are subject to the same depreciation set up by standing long periods until a new field calls for their removal and erection on other foundations.

It should be noted, as a secondary matter, that the use of the air or gas lift does away with the pull rods and individual pumping engines. The air lines to the well and the oil lines are buried below plow depth, this leaving a clear field for farming which is a necessary consideration when working on cultivated land.

After a well is brought in and the shut-in pressure is obtained, the production is known and the proper design of flow pipe should be installed and the well allowed to operate as a natural lift. If the quantity of fluid is considerable, say 1,000 bbl. per day, and the pressure has been reduced to about 200 lb. a compressor should be installed to provide additional energy in order to keep the well producing at the maximum for as long a period as possible. In certain fields, as at Goose Creek, Hull, Currie, and West Columbia, where large quantities of water accompany the oil, the air lift should be kept in operation for a comparatively long time after the gas pressure has declined and become practically negligible. It could be used today in some of the fields where production has dropped to a low point owing to the limitation of the beam pump for handling large quantities of fluid.

The power required, velocities, and friction-head losses of the input or inflowing compressed gas are matters of design based on the principles and working rules for the flow of gas which have application in many other lines of work.

The design work for oil flow on such can be based on the data and principles employed in oil pipe line work; but in the case of a lift where the proportion of gas and oil by volume vary from the conditions of liquid flow to the verge of a moving mass of very wet vapor, if not gaseous flow, the principles to be applied are not so well defined but have been covered by thermodynamic formulæ.

Shaw[1] discussed some of the points entering into the design of an installation:

"There are three general types of air-lift installations as follows [see Fig. 121]:

1. Two pipes, side by side, connected near the lower end, the air flowing through one of the pipes to the connection and the mixed air and liquid rising through the other pipe.
2. Two pipes, one inserted in the other and the air flowing through the inner pipe to the lower end, the mixture of air and liquid rising in the annular space between the two pipes. This is called the 'central air lift system.'
3. Two pipes, one inserted in the other, the air passing through the annular space between the two pipes, the mixture of air and liquid rising in the inside pipe. This is called the 'Saunders system.'"

"In the first type, a fluid level is maintained which can be measured. In the second and third types the fluid column is in motion in both pipes and submergence cannot be actually measured, but the level to which the fluid would rise at the instant the air is cut off from the air pipe can be determined by noting the gage pressure at the top of the well and subtracting from this the friction loss due to the air flowing through the air pipe, thus obtaining the pressure at the bottom of the air pipe. The feet of corresponding submergence can then be determined from this figure of pressure, making allowance for the specific gravity of the particular liquid being lifted."

"The first type permits a higher efficiency to be obtained than any other method. In oil wells, however, the diameters of casing are usually so small that rarely can the required capacity be obtained by having separate lines side by side within the casing. It is difficult, moreover, to lower and raise in the casing two separate lines which are connected at the lower end."

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[1] SHAW, S. F., Principles of the Air and Gas Lift, *Oil and Gas. Jour.*, p. 374, June 16, 1927.

"The second type will cause a flow in 'heads' unless the design is very close to being correct. Between heads the pressure will build up until the maximum point is reached, at which time the well will head and the pressure will drop to its minimum point. Between heads there is usually a continuous discharge of air or gas from the annular opening between the casing and tubing which represents lost energy."

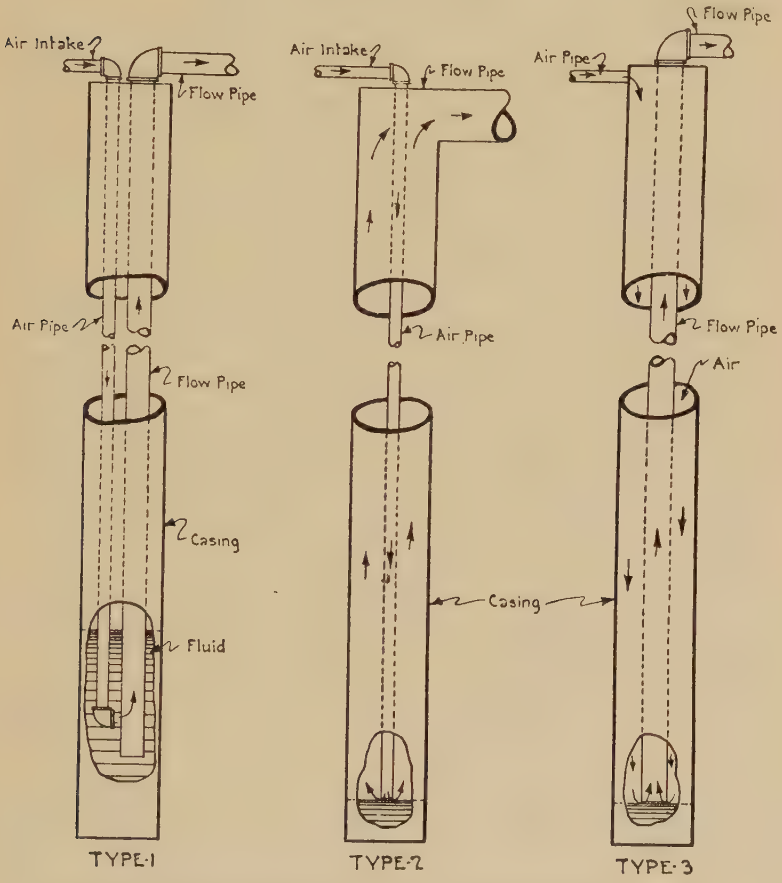
Air Intake
Flow Pipe
Air Pipe
Flow Pipe
Casing
Fluid
TYPE-1
Air Intake
Flow Pipe
Air Pipe
TYPE-2
Flow Pipe
Air Pipe
Flow Pipe
Air
Casing
TYPE-3

Fig. 121.—Three general types of air gas lift arrangement. (*Shaw.*)

"In the third type as it is usually installed, the well nearly always flows in heads unless the design is nearly correct or unless an excessive quantity of gas is employed. The interval between heads is usually longer than in the second method. The range of pressure is usually greater than in the second type. At the beginning of a head there is often ejected a 'plug' of liquid unmixed with gas which results from displacement of the liquid in the casing by the air. This plug is quickly followed by a mixture of gas and liquid which is then followed by a longer period of almost pure gas which flows into the tubing from the space between the casing and tubing. This flow of gas continues until the pressure drops to its low point when the incoming liquid rises and closes off the escape of the gas. The waste of energy when flowing by heads in this manner is very great. Flowing in heads serves to build up a much higher pressure than when flowing continuously and thereby establishes temporarily a high back pressure against the sand and probably retards, in some cases to a considerable extent, the flow of the oil toward the well."

"A continuous flow is more efficient than an intermittent flow because of requiring a small volume of gas to raise a barrel of oil; it operates under a lower pressure than the maximum pressure reached in intermittent flows, being nearer the lower point than the higher point. The fluid level is lowered to a lower point than the average level when operating by heads. It is very important to lower the fluid level to the point at which the maximum flow toward the well takes place, thereby creating a differential pressure between the sands and the well opening."

Relative to the design of air-lift pumps for handling water, and these same principles apply in general application to the lifting of oil, A. and Z. Daw[1] state as follows:

"In the design of an air-lift pump the designer has under his control:

"1. The depth of immersion of the rising main which governs the ratio of submergence to lift, and the working air pressure. It should also be noted that the frictional resistance and other losses are directly related to the depth of submergence.

"2. The diameters of the rising and air mains and velocity of flow therein. In proportioning the size of the mains, it should be kept in mind that frictional resistances increase proportionally to the square of the relative velocities, and decrease in direct ratio with increase in diameter of the mains. The velocity of flow in the rising main affects the bouyant effort and eddying motion losses, the greater the velocities the smaller are these losses.

"3. The design and size of holes in the footpiece for the ingress of the air to the eduction pipe which affect the relative size of the air bubbles in the rising main, and consequently the slippage losses, as the smaller the air bubbles, provided they are intimately mixed with the water, the less will be the slippage losses due to the buoyant effort and eddying motions."

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[1] Daw, A. and Z., "Compressed Air Power" p. 293.

"With so many variable conditions the designer will require to make several calculations to proportion the submergence, size of mains, and velocity of flow to arrive at the conditions of highest efficiency for the particular well."

The basic problem in design is to proportion the size of the tubing in the well, be it flowed through the tubing or the annular space, so as to keep all friction losses, both liquid and gaseous, at a minimum; to maintain slippage losses at a minimum and to have ample flow area so that the well can produce all available oil. These considerations call for a study of fluid flow and friction effects.

If low input pressures and large volumes are to be used on the operating system, naturally large flow areas must be provided. When the tubing is set low, that is with high submergences, high starting pressure will be necessary. The use of large tubing for handling large volume calls for a certain length, say 50 to 100 ft., of smaller tubing at the bottom to prevent heading, the resulting action being that of a tapered string in minor degree. The larger the tubing size the lower it can be placed in the well; the smaller the string the higher it must be placed due to the friction effects.

In annular space flowing, the 2½-in. tubing, if it leaves sufficient space for the liquid flow, seems to be the most common size employed; the 2-in. size gives greater space when required but also increases the gas friction losses, especially where comparatively high pressures are required at the footpiece, or perforations. As a matter of general practice, when the oil string is 6⅝- or 6¼-in. casing, the 2½-in. tubing, upset, is used and 2-in. tubing for wells finished with 5³⁄₁₆-in. casing. One case of successful low-pressure high-volume operation took place in a well finished with 6⅝-in. casing and a string of 5³⁄₁₆-in. pipe in use as tubing; this string had a perforated length at the bottom and was set on the sand. It could have been hung from the top if the pressure had so necessitated. It should be needless to state that the well was flowed through the 5³⁄₁₆-in. pipe.

Brundred[1] covers the subject of tubing sizes as follows:

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[1] BRUNDRED, L. L., Practical Production of Oil by Gas Lift, *Oil Weekly*, Nov. 11, 18, 25, 1927.

"A number of factors enter into a determination of the size of tubing to be selected, the most important of which are as follows:

a. Volume of fluid to be lifted.
b. Percentage of water present.
c. Size of smallest casing in the well.
d. Viscosity of oil.
e. Distance fluid must be raised.
f. Total gas to oil ratio necessary.
g. Whether or not excessive paraffin is present.

"The following table has been prepared on the basis of raising 32° gravity oil, with little water present, from a depth of 3,500 ft., assuming that the oil string is 6⅝ or 6¼ in.

Barrels of fluid to be raised	Size tubing customarily used, inches
5 to 100	2
100 to 300	2½
300 to 600	3
600 to 2,000	4
2,000 to limit	4½

"It must be understood that this table is furnished as a guide only and that operators in each field must work out their sizes to meet conditions encountered there."

"Considerable experimental work has been done with the use of telescopic tubing, or a string of tubing of two or more sizes, increasing in diameter from the bottom to the top of the well. There is no doubt but that this increased area towards the top of the well is an advantage as it successively establishes somewhat lower velocities throughout the upper portion of the tubing than in one of unit size throughout its entire length."

"This arrangement, however, is subject to disadvantages, some of which are as follows:

a. The sudden increase in the area of the tubing, if standard connections were used, would set up considerable turbulence at this point, causing separation of the fluid and gas, with probable surging. This increased turbulence, no doubt, would result in increased friction at the point of change in tubing size so that the lowered velocity is not in all cases entirely effective.

b. The impracticability of running a swab or scraper, if this arrangement is used, is apparent."

"Considering both the advantages and disadvantages, it is believed that the disadvantages far outweigh any advantages gained, and it is, therefore, recommended that the unit size string of tubing be used."

In case a well is flowing during or just prior to the time of installing a lift, the production gives a basis for determining the required pipe sizes to handle the flow. In case swabbing must be resorted to in order to learn what amount of oil the well will produce, the production when on lift, will in most cases amount to from four or five times the swabbed production, if the latter is about 100 barrels; two or three times a swabbed production if 200 barrels; and one and one-half to two times, if the swabbed production is 500 barrels. It is realized that these are the most general factors but are offered here in hopes that better data may later become available.

While it is realized that most engineers have their favorite tables for the determination of friction resulting from fluid flow, both liquid and gases, some handy tables are inserted here.

The data of Table XXXIX were given by Shaw[1] in one of his articles. To modify the losses indicated by Table XXXIX from the conditions of the flow of air to the flow of gas, Shaw supplied the following data, the basis of which is the varying density of the gas as compared with air:

Some air-gas lift engineers have stated that the frictional losses resulting from the flow of the air or gas may be safely ignored but the writer believes that these losses should be considered, for it is easy to picture conditions where the whole of the input pressure could be consumed in an effort to get the air or gas down to the perforation or footpiece, if a large volume is used on a small flow area with its resulting high velocity.

The figures of recommended air or gas velocities vary from 20 to 70 ft. per second but rather than adhere to any set "best velocity" the most economical velocity from the standpoint of cost of installation and compression should be adopted.

A discussion of air flow, velocity, and friction considerations is given by Daw[2] and also in the standard handbooks and textbooks usually available.

[1] Shaw, S. F., Principles of the Air and Gas Lift, *Oil and Gas Jour.*, pp. 378–380, June, 16, 1927.

[2] Daw, A. and Z., "Compressed Air Power," p. 111, 1920 ed.

TABLE XXXIX.—FRICTION OF AIR IN PIPES

Divide the number corresponding to the diameter and volume by the ratio of compression. The result is the loss in pounds per square inch in 1,000 ft. of pipe

Cubic feet free air, per minute	Nominal diameter, inches								
	½	¾	1	1¼	1½	1¾	2	2½	3
5	12.7	1.2							
10	50.7	7.8	2.2						
15	114.1	17.6	4.9						
20	.....	30.4	8.7	2.0					
25	.....	50.0	13.6	3.2					
30	.....	70.4	19.6	4.5					
35	.....	95.9	26.6	6.2	2.7				
40	.....	125.3	34.8	8.1	3.6	1.9			
45	.....	.....	44.0	10.2	4.5	2.4			
50	.....	.....	54.4	12.6	5.6	2.9			
60	.....	.....	78.3	18.2	8.0	4.2	2.2		
70	.....	.....	106.6	24.7	10.9	5.7	2.9		
80	.....	.....	139.2	32.3	14.3	7.5	3.8		
90	.....	.....	.....	40.9	18.1	9.5	4.8		
100	.....	.....	.....	50.5	22.3	11.7	6.0		
110	.....	.....	.....	61.1	27.0	14.1	7.2	2.8	
120	.....	.....	.....	72.7	32.2	16.8	8.6	3.3	
130	.....	.....	.....	85.3	37.8	19.7	10.1	3.9	
140	.....	.....	.....	98.9	43.8	22.9	11.7	4.6	
150	.....	.....	.....	113.6	50.3	26.3	13.4	5.2	
160	.....	.....	.....	129.3	57.2	29.9	15.3	5.9	
170	.....	.....	.....	.....	64.6	33.7	17.6	6.7	
180	.....	.....	.....	.....	72.6	37.9	19.4	7.5	
190	.....	.....	.....	.....	80.7	42.2	21.5	8.4	2.1
200	.....	.....	.....	.....	90.4	46.7	23.9	9.3	2.9
220	.....	.....	.....	.....	108.2	56.5	28.9	11.3	3.5
240	.....	.....	.....	.....	128.7	67.3	34.4	13.4	4.2
260	.....	.....	.....	.....	.....	79.0	40.3	15.7	4.9
280	.....	.....	.....	.....	.....	91.6	46.8	18.2	5.7
300	.....	.....	.....	.....	.....	105.1	53.7	20.9	6.6

Cubic feet free air, per minute	Nominal diameter, inches								
	2	2½	3	3½	4	4½	5	6	8
320	61.1	23.8	7.5	3.5					
340	69.0	26.8	8.4	3.9					
360	77.3	30.1	9.5	4.4					
380	86.1	33.5	10.5	5.9					
400	94.7	37.1	11.7	5.4	2.7				
420	105.2	40.9	12.9	6.0	3.1				
440	115.5	44.9	14.1	6.6	3.4				
460	125.6	48.8	15.4	7.1	3.7				
480	.....	53.4	16.8	7.8	4.0				
500	.....	58.0	18.3	8.5	4.3				
525	.....	64.2	20.2	9.4	4.8	2.6			
550	.....	70.2	22.1	10.2	5.2	2.9			
575	.....	76.7	24.2	11.2	5.7	3.1			
600	.....	83.5	26.3	12.2	6.2	3.4			
625	.....	92.7	28.5	13.2	6.8	3.7			
650	.....	98.0	29.9	14.3	7.3	4.0			
675	.....	105.7	33.3	15.4	7.9	4.3			
700	.....	113.7	35.8	16.6	8.5	4.6			
750	.....	130.5	41.1	19.0	9.7	5.3	2.9		
800	.....	.....	46.7	21.7	11.1	6.1	3.3		
850	.....	.....	52.8	24.4	12.5	6.8	3.8		
900	.....	.....	59.1	27.4	14.0	7.7	4.2		
950	.....	.....	65.9	30.5	15.7	8.6	4.7		
1,000	.....	.....	73.0	33.8	17.3	9.5	5.2		

Table XXXIX (*Continued*)

Cubic feet free air, per minute	Normal diameter inches								
	2	2½	3	3½	4	4½	5	6	8
1,050	.....	.....	80.5	37.3	19.1	10.4	5.8		
1,100	.....	.....	88.4	40.9	21.0	11.5	6.3	2.4	
1,150	.....	.....	96.6	44.7	22.9	12.5	6.9	2.6	
1,200	.....	.....	105.2	48.8	25.0	13.7	7.5	2.8	
1,300	.....	.....	123.4	57.2	29.3	16.0	8.8	3.3	
1,400	.....	.....	.....	66.3	33.9	18.6	10.2	3.8	
1,500	.....	.....	.....	76.1	39.0	21.3	11.8	4.4	
1,600	.....	.....	.....	86.6	44.3	24.2	13.4	5.1	
1,700	.....	.....	.....	97.8	50.1	27.4	15.1	5.7	
1,800	.....	.....	.....	110.0	56.1	30.7	16.9	6.4	
	Nominal diameter, inches								
	4	4½	5	6	8	10	12		
1,900	62.7	34.2	18.9	7.1					
2,000	69.3	37.9	21.3	7.8					
2,100	76.4	40.8	23.0	8.7	2.0				
2,200	83.6	45.8	25.3	9.5	2.2				
2,300	91.6	50.1	27.6	10.4	2.4				
2,400	99.8	54.6	30.1	11.3	2.6				
2,500	108.3	59.2	32.6	12.3	2.9				
2,600	117.2	64.0	35.3	13.3	3.1				
2,700	.....	69.1	38.1	14.3	3.3				
2,800	.....	74.3	41.0	15.4	3.6				
2,900	.....	79.8	43.9	16.5	3.9				
3,000	.....	85.2	47.0	17.7	4.1				
3,200	.....	97.1	53.5	20.1	4.7				
3,400	.....	109.5	60.7	22.3	5.3				
3,600	.....	122.8	67.7	25.4	5.6				
3,800	.....	.....	75.5	28.4	6.6				
4,000	.....	.....	83.6	31.4	7.3				
4,200	.....	.....	92.1	34.6	8.1				
4,400	.....	.....	101.2	38.1	8.9				
4,600	.....	.....	110.5	41.5	9.7	2.9			
4,800	.....	.....	120.4	54.2	10.5	3.2			
5,000	.....	.....	.....	59.1	11.5	3.4			
5,250	.....	.....	.....	54.1	12.6	3.8			
5,500	.....	.....	.....	59.4	13.9	4.2			
5,750	.....	.....	.....	64.9	15.2	4.6			
6,000	.....	.....	.....	70.7	16.5	5.0			
6,500	.....	.....	.....	82.9	19.8	5.9	2.3		
7,000	.....	.....	.....	96.2	22.5	6.8	2.6		
7,500	.....	.....	.....	110.5	25.8	7.8	3.0		
8,000	.....	.....	.....	125.7	29.4	8.8	3.6		
9,000	.....	.....	.....	.....	37.2	11.2	4.4		
10,000	.....	.....	.....	.....	45.9	13.8	5.4		
11,000	.....	.....	.....	.....	55.5	16.7	6.5		
12,000	.....	.....	.....	.....	66.1	19.8	7.7		
13,000	.....	.....	.....	.....	77.5	23.3	9.0		
14,000	.....	.....	.....	.....	89.9	27.0	10.5		
15,000	.....	.....	.....	.....	103.2	31.0	12.0		
16,000	.....	.....	.....	.....	117.7	35.3	13.7		
18,000	.....	.....	.....	.....	148.7	44.6	17.4		
20,000	.....	.....	.....	.....	.....	55.0	21.4		
22,000	.....	.....	.....	.....	.....	66.9	26.0		
24,000	.....	.....	.....	.....	.....	79.3	30.1		
26,000	.....	.....	.....	.....	.....	93.3	36.3		
28,000	.....	.....	.....	.....	.....	108.0	32.1		
30,000	.....	.....	.....	.....	.....	123.9	48.2		

Note: This table printed by permission of the School of Mines and Metallurgy, University of Missouri.

TABLE XL.—QUANTITY BY WHICH FRICTION LOSS CALCULATED FOR AIR IS TO BE DIVIDED TO OBTAIN FRICTION LOSS OF A GAS OF GIVEN SPECIFIC GRAVITY

Specific gravity, gas	Factor	Specific gravity, gas	Factor	Specific gravity, gas	Factor
0.56	1.3363	0.82	1.1043	1.08	0.9623
0.57	1.3245	0.83	1.0976	1.09	0.9578
0.58	1.3131	0.84	1.0911	1.10	0.9535
0.59	1.3019	0.85	1.0847	1.11	0.9492
0.60	1.2910	0.86	1.0783	1.12	0.9449
0.61	1.2804	0.87	1.0721	1.13	0.9407
0.62	1.2700	0.88	1.0660	1.14	0.9366
0.63	1.2599	0.89	1.0600	1.15	0.9325
0.64	1.2500	0.90	1.0541	1.16	0.9285
0.65	1.2403	0.91	1.0483	1.17	0.9245
0.66	1.2309	0.92	1.0426	1.18	0.9206
0.67	1.2217	0.93	1.0370	1.19	0.9167
0.68	1.2127	0.94	1.0314	1.20	0.9129
0.69	1.2039	0.95	1.0260	1.21	0.9090
0.70	1.1952	0.96	1.0206	1.22	0.9054
0.71	1.1868	0.97	1.0153	1.23	0.9017
0.72	1.1785	0.98	1.0102	1.24	0.8980
0.73	1.1704	0.99	1.0050	1.25	0.8944
0.74	1.1625	1.00	1.0000	1.26	0.8909
0.75	1.1547	1.01	0.9950	1.27	0.8874
0.76	1.1471	1.02	0.9901	1.28	0.8839
0.77	1.1396	1.03	0.9853	1.29	0.8805
0.78	1.1323	1.04	0.9806	1.30	0.8771
0.79	1.1251	1.05	0.9759	1.31	0.8737
0.80	1.1180	1.06	0.9713	1.32	0.8704
0.81	1.1111	1.07	0.9667	1.33	0.8671

As rock pressure subsides, which it inevitably does, should the working pressure of introduced gas or air exceed the rock pressure, trouble starts in a badly designed piping job, for practically all sands are sensitive to back pressures greater than rock pressures.

While it is necessary, for efficient work, to hold as much back pressure on a sand as will secure an equal quantity of oil without excessive formation gas production, still, a piping job that sets up losses of pressure that require sending greater pressures down into the well, particularly the deeper wells, should be replaced with a piping layout in which pressures are held within limits that permit operating at the maximum of oil production with the minimum of formation gas production and minimum of introduced gas.

The use of air lift in a flowing well that has such pressure that piping cannot be introduced into the well is, of course, impossible, although it would be beneficial at this state of production to produce as much as possible with introduced gas as a means of holding formation gas in the oil sand for its more valuable duty of driving oil toward and into the well bore.

Concerning liquid flow as applied to the lift application, Pennington[1] states:

"After air or gas has been finely divided into small bubbles and mixed with the oil entering flow line, the size of flow line, or eduction tube, is the one governing factor controlling efficiency most."

"Velocity at entrance to flow line should be the controlling velocity, for where wells are shallow, the exit velocity is less than where wells are deep because of the usually greater pressures required for the deeper wells."

"Entrance velocity is the velocity of the oil and gas or air mixture and may be held within the usual velocities found practicable in hydraulics, or from 8 to 12 ft. per second, with 10 ft. as an average."

"At 10 ft. per second, discharge of the quantities of oil shown below are such that the greater number of wells can be pumped with the central air system which, in the writer's experience, is by far the best and most efficient method of pumping, rather than using a central pipe for air or gas inlet and the casing for discharge, for several reasons. One reason is that a smooth interior pipe offers less friction to the passage of oil, and since the velocities at the upper end are great, depending upon air inlet pressure, this becomes a factor that must be considered. Flowing up the casing, around the air line, with air-line couplings interfering with easy flow, makes for waste in gas and power. Should sulphur compounds and the rapid flow of oil and gas or air set up corrosion, a flow line receives this corrosion and the well casing is not damaged. The uptake area of flow line may be changed more readily than where the size of casing is fixed, thus fixing the uptake area."

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[1] PENNINGTON, HARRY, Lift Efficiency Depends upon Skill in Design and Operation, *Oil Weekly*, p. 72, Aug. 19, 1927.

"Uptake area is a matter of the most concern, for the quantity of oil-gas or oil-air mixture, per square inch of uptake area, controls the operating efficiency in equally aerated mixtures."

Table XLI

Size of pipe, inches	Capacity of pipe in barrels of 42 gal. each, per 24 hr., at velocity of 10 ft. per second
1	835
1¼	1,251
1½	2,270
2	3,489
2½	5,232
3	7,545
3½	10,252
4	13,406
4½	16,992
5	20,880

"This table, from the writer's notes, when used in connection with quantities of air, or gas, fixes the size of eduction line, or flow line. For instance, when a working pressure of 300 lb. is fixed, the number of atmospheres of pressure is 21, and the volume of free air is, therefore, reduced to $1/21$. Using, say, 500 cu. ft. of free air or gas per barrel of oil, without considering solubility, whether gas is pumped in, or whether it is evolved from the formation, the total volume of 1 bbl. of oil and 500 cu. ft. of gas at 300 lb. is 29.3 cu. ft. A well making 1,000 bbl. in 24 hr., then, would pass 29,320 cu. ft. of gas-oil mixture or 5,232 bbl. which, at 10 ft. per second inlet velocity, would require a 2½-in. flow line."

"To pass 1,000 bbl. of oil up inside of 6⅝-in. casing, with a 2½-in. gas line taking the gas down, means that the uptake area is so great that the velocity is too low for effective work. The velocity should be held high to prevent slippage of gas bubbles through the oil, but it cannot be held too high for the reason that friction increases as the square of velocity. Ten feet per second inlet velocity of the mixture is not excessive and in short lines of low lifts may be exceeded, but where the expansion of the number of atmospheres of operating pressure is great, excessive expansion at the upper end of the flow line sets up high velocities that lower efficiency, and where this is the case, enlarged upper portion of flow lines will serve to hold the velocities at the upper end of the piping low enough for good economy."

"Velocities of 60 to 80 ft. per second at the outlet have been observed by the writer, but these are where the gas quantity and pressure are excessive; reducing the gas-oil ratio in such cases not only serves to secure a greater total recovery, but also secures a greater duty out of the gas pumped in. As noted before, however, outlet velocity depends upon the expansions, and these high velocities are not always reducible except by enlarging flow line at intervals up to the surface, for the beginning point is the inlet velocity."

After discussing certain methods of installing and operating the lift where the air or gas acts as pistons or appears as "gulps," the writer goes on to state that:

"This method of operation does not mingle the air or gas intimately with oil, and this has given rise to the use of footpieces of various designs, for, when air or gas has been closely intermingled with oil, the mixture is in condition to afford high lifting efficiency, provided of course that the remainder of the design is correct, for no footpiece can correct all errors of an installation."

"For instance, when the uptake pipe is too large for securing sufficiently high velocity, or is too small and the velocity is too high, there is nothing that a footpiece can do toward correcting velocity. This resolves the air or gas lift into just two necessary things—the smallest bubbles obtainable and the correct uptake velocity."

The matter of "best velocity" of the liquid flow appears in recommended velocities up to 20 to 25 ft. per second but here again the best velocity, economically, should be found for the conditions at hand.

Tables and formulæ giving the pressure drops and friction losses for liquid flow, both water and oil, are usually available in different forms. The matter of oil flow as applied to a flowing well was discussed previously in this work. Due to the viscosity and density differences in different oils, the formulæ for oil flow are necessarily more complicated than the formulæ for water flow, but, when the average oil of some particular field is being worked with, certain flow constants can be arrived at in comparison with water flow and utilized to advantage in the work on that oil. For instance, after comparison of the flowing characteristics of one oil with water, it was determined that the losses due to friction were 1.24 times the water friction losses. The use of this figure simplified all calculations thereafter in all practical work.

A tapered flow line is, theoretically, more efficient than a straight one, if it were in the form of a true hyperbolic cone throughout its length. It is however, impossible to obtain such a line and it is the opinion of some authorities that a tapered line with abrupt changes in diameter would be less efficient than a proper size line of uniform cross-section. This is on account of sudden changes in velocity due to the variation in pipe size.

Experiments have shown that in most cases it is advisable to flow the oil through a string of tubing rather than between the tubing and casing. There is less contact surface and less internal friction in flowing through tubing, the ratio of the contact surface being dependent upon the size of flow line and size of casing used. There is additional friction when flowing between tubing and casing on account of turbulence caused by the collars on the flow line.

Another important reason for flowing through tubing is that the tubing can be replaced with greater ease and less cost than casing, where the pipe becomes destroyed by corrosion from bad water and gas. This is especially true where sulphur water is produced along with oil, and air is used as the lifting medium. In some installations, flow lines have lasted but a very few weeks. If the oil is flowed between the tubing and casing, under these conditions destruction of the casing occurs which would ruin the well in the same period of time.

The following two examples of calculations relating to lift performance of assumed operating conditions in wells are included here as giving some ideas which may assist in the formulation of a systematized procedure for any set of conditions.

The first example is from the paper by Pierce and Lewis.[1]

"The following data on two wells illustrates the author's methods of working up for comparison the data gathered on flowing wells. From the examination of the data so tabulated, and compared with experience factors and certain fundamental curves prepared to fit in with the experience factors and data, deductions can be made, indicating the present efficiency relation to a deduced possible efficiency of flow under improved methods and conditions."

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[1] Pierce, H. R., and J. O. Lewis, Principles of Air-gas Lift As Applied to Oil Production, *Petroleum Development and Technology*, p. 19, 1927.

"The gain of such changes as are necessary then may be balanced against the expense and time lost in making the changes."

METHOD OF WORKING UP DATA FOR PURPOSES OF COMPARISON

	Well 1	Well 2
1. Barrels oil per day	2,860	200
2. Barrels water per day		
3. Total fluid per day, barrels	2,860	200
4. Total fluid per second, cubic feet	0.1861	0.0130
5. Gas furnished per day, cubic feet	480,000	650,000
6. Natural gas per day, cubic feet	1,305,000	185,000
7. Total gas per day, cubic feet	1,785,000	835,000
8. Total gas per second, cubic feet	20.68	9.67
9. Total gas-oil ratio, cubic feet per barrel	624	4,175
10. Furnished gas-oil ratio, cubic feet per barrel	168	3,250
11. Natural gas-oil ratio, cubic feet per barrel	456	925
12. Weight total liquid per second, pounds	9.55	0.68
13. Weight total gas per second, pounds	1.55	0.72
14. Total weight lifted per second	11.10	1.40
15. Depth of tubing	4,216	4,108
16. Submergence, feet	1,340	264
17. Lift, feet	2,876	3,844
18. Velocity at top, feet per second V_2	114.0	41.4
19. Velocity at bottom, feet per second V_1	8.44	7.42
20. Difference in velocity, $V_2 - V_1$	105.56	33.98
21. P_1 absolute	499.4	126.4
22. P_1 corrected absolute, bottom well	493.0	109.7
23. P_2 corrected absolute	28.4	19.4
24. $R_1(P_1/P_a)$	34.23	7.62
25. $R_2(P_1/P_2)$	17.36	5.66
26. Total work in gas through R_1, foot-pounds per second	151,500	40,700
27. Total work in gas through R_2, foot-pounds per second	121,750	34,780
28. Total work lifting liquid plus gas plus acceleration, foot-pounds per second	33,834	5,407
29. Total work lifting liquid, foot-pounds per second	27,450	2,614
30. Total work lifting gas, foot-pounds per second	4,460	2,768
31. Total work lifting acceleration liquid plus gas, foot-pounds per second	1,924	25
32. Total work unaccounted for, foot-pounds per second	87,916	29,373
33. $E_1 \dfrac{\text{Work lifting liquid}}{\text{Work in gas through } R_2,}$ percentage	22.60	7.53
34. $E_2 \dfrac{\text{Work lifting gas}}{\text{Work in gas through } R_2,}$ percentage	3.67	7.97
35. $E_3 \dfrac{\text{Work of acceleration}}{\text{Work in gas through } R_2,}$ percentage	1.58	0.07
36. $E_4 \dfrac{\text{Work lifting liquid plus gas plus acceleration}}{\text{Work in gas through } R_2}$ percentage	27.85	15.57
37. $\dfrac{\text{Unaccounted for work}}{\text{Work in gas through } R_2,}$ percentage	72.15	84.43

The next example is one of Shaw's,[1] it being noted how the computation is based on the standardized work in connection with lifting water:

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[1] SHAW, S. F., Principles of the Air and Gas Lift, *Oil and Gas Jour.*, p. 376, June 16, 1927.

"An example will be given of the manner in which the efficiency of a gas lift is computed, assuming the following conditions:

Total depth of well, or length of air tubing, 4,000 ft.
Barrels produced, per day, 3,000.
Gravity of the oil, 41° Bé., or specific gravity of 0.82.
Total gas produced per day, 2,700,000, or 900 cu. ft. per barrel.
Total gas input from compressor, 660,000 cu. ft., or 458 cu. ft. per minute.
Total gas associated with the oil, 2,040,000 cu. ft., or 680 cu. ft., per barrel.
Pressure at top of well, 190 lb.
Diameter of air tubing, 2½ in."

"It is first necessary to ascertain the pressure at the lower end of the tubing, and from Tables XXXIX and XL, the friction loss of 458 cu. ft. per minute passing through a 2½-in. pipe, 4,000 ft. in length is found to be 13.8 lb. for air, and for gas at specific gravity of 0.8 would be 13.8 ÷ 1.118 or 12 lb.; the required pressure would then be 190 less 12 lb. or 178 lb. per square inch. The height of an equivalent column of water is 178 × 2.304 or 401 ft., and the equivalent column of oil of 0.82 specific gravity is 401 ÷ 0.82 or 490 ft. which is the submergence in this case. The lift is then 4,000 ft. less 490 ft. or 3,150 ft. The quantity of air required to lift 1 gal. of water 3,510 ft. at efficiency of 100 per cent with submergence of 178 lb. is 5.401 cu. ft. (see Table XXIV) and to raise 1 gal. of oil of 0.82 specific gravity is 5.401 × 0.82 or 4.429 cu. ft.; and per barrel of oil would be 4.429 × 42, or 186.6 cu. ft. The efficiency is then 186.6 ÷ 900, or 20.7 per cent. If it were required to determine the size of the compressor to compress the gas necessary to admit to the well for the above conditions, assuming the other conditions are known other than this factor, and assuming the design of the gas lift were such as to occasion, for example, the following losses:

	Percentage
Entrance losses at lower end of footpiece	10
Slippage and friction losses in eductor	50
Losses at discharge	19.3
Total	79.3

"This would leave an efficiency of 20.3 per cent that would be obtained. Under the conditions of lift and submergence assumed, the quantity of gas required at 100 per cent is found as above to be 186.6 cu. ft. per barrel, and at 20.3 per cent efficiency would require a total of 186.6 ÷ 20.3 or 900 cu. ft. per barrel. We have previously assumed that the quantity of gas per barrel derived from the sand is 680 cu. ft., therefore, the quantity required from the compressor would be 900 minus 680, or 220 cu. ft. per barrel and for 3,000 bbl. per day the total quantity required would be 3,000 × 220 or 660,000, which is 458 cu. ft. per minute. If we assume that the compressor has a volumetric efficiency of 80 per cent, the displacement capacity of the compressor must be 460 ÷ 80, or 575 cu. ft. per minute. It should be remembered that this applies to sea level altitude or close to sea level. If air-lift work were to be attempted at such places as Wellington, Colo., or Salt Creek, Wyo., allowance would need to be made for this difference in altitude."

Summarizing, the following notes are applicable to all lift installations, it being remembered that a column of oil is lighter and exerts less pressure than an equivalent water column in the ratio of the specific gravity of the oil to 1.

The delivery pipe, open at both ends is submerged to a depth proportionate to, but always greater than, the height to which the fluid is to be raised.

If the discharge pipe be of very small diameter, say 1 in. or smaller, the compressed air entering the bottom tends to form piston-like layers, which rise rapidly, alternating with masses of fluid, as is shown by experimenting with glass tubes. If the discharge pipe is of large diameter, the air is best admitted through a series of small holes or nozzles, resulting in a more complete dissemination of the air through the mass of rising fluid. The fluid is raised chiefly by the aeration of the column, which causes a reduction in its specific gravity; added to this is the expansive force and kinetic energy of the compressed agent.

Referring to Fig. 99 which shows the essential features of a lift, let

$L + D$ = depth of the delivery pipef ootpiece below the normal fluid level, before pumping begins, or when the fluid is at rest.
D = height of fluid level when the pump is in operation.
H = height of the column of mixed air and fluid, measured from the air inlet to a point of discharge.
L = net height of lift = $H - D$.

The compressed air enters the footpiece at a pressure P', corresponding to the head H. Assuming that the fluid rises in piston-like masses, as would be the case with a single air nozzle and a delivery pipe of small diameter, the sum of the length of these masses in the column H must, theoretically, be equal to the outside solid column of fluid D, the weight of the compressed air contained in the column being neglected or the equivalent pressure artificially supplied. But, to overcome the frictional resistance and produce flow, the head D must be greater. Under ordinary working conditions, the net height of lift L is found to be from $0.5D$ to, say, $0.65D$. Taking the second value and transposing:

$D = L/0.65$; and by substituting in the expression for the value of P', as above, $P' = 0.434\frac{L}{0.65} = 0.67L$ for water. If, for example, L be 50 ft., $P' = 33.5$ lb., and $D = 50/0.65 = 77$ ft.

Care should be taken in the design of the footpiece and in properly proportioning the air pressure to the submergence and net lift. Otherwise, air may leak back into the sump or outside column of fluid, and if this becomes aerated, much more power and a larger volume of air will be required to keep the pump in operation, thus reducing the efficiency.

Starting pressure is equal to the depth of footpiece in the well, less the fluid head in feet times 0.434 for water. Working pressure is equal to the depth of footpiece, less the pumping head times 0.434 plus friction in air pipe plus 2 lb. back pressure in the nozzle or footpiece.

Though the question of relative sizes of air and delivery pipes has not yet been satisfactorily answered, it is probable that ratios of diameter from 1:2 up to 1:2¼ or 3 will be found suitable. The absolute diameters are determined on the basis of frictional loss caused by the flow in the pipes. A fluid velocity of 250 to 300 ft. per minute may be assigned for the delivery pipe. To give an accelerated velocity to the mixed air and water on entering the delivery pipe, some installations have a venturi throat above the footpiece.

It is thought that the method used, temperatures employed, and other governing features of control, as included in the gas-lift system, may be highly successful with oils of high paraffin content and virtually eliminate the occurrence of paraffin as a troublesome condition in so far as oil recovery from the well is concerned.

If insufficient gas is available to flow a well, it will head and flow at regular intervals. Too large a flow line will cause the same thing to occur, on account of slippage. This condition may be remedied by providing sufficient gas for flowing or by changing the size of the flow line, or both.

Improper depth of flow line will result in too high or too low pressures on the producing formation. If the pressures are too high, the production will be retarded. This may be changed by the lowering of the flow line. If pressures are too low on the formation, production will be too fast and water encroachment may occur. This condition may be remedied by raising the tubing off bottom to effect the proper back pressure, or by beaning at the well head.

If too much gas is used it will slip through the oil doing no work, giving abnormal gas factors, and requiring excessive compression costs. Too much gas also denudes the oil of its lighter fractions and lowers its gravity. The proper volume to use can be determined only by observation and test.

If a too small flow line is used, the maximum production of the well cannot be maintained and high working pressures will be required. The production of some wells has been more than doubled by changing the size of flow lines. The proper size cannot be determined except by test and a study of the individual well characteristics.

Wells which produce some water along with the oil must be carefully watched or they may be ruined. This has been the past result in some fields where wells producing water have been put on the gas lift.

Input pressures, as recorded on pressure gages, are criterions of actual conditions existing in wells. Where automatic controls are installed sharp waves in the lines indicate too much gas. The abrupt peaks occur when slippage takes place. Waves which are smooth and rounded over indicate partial heading and insufficient gas. Where the proper amount of gas is being circulated, the curve will be smooth and regular. The curves drawn on the recording charts serve as indexes of operating efficiency. Paraffin accumulations are indicated by a gradual rise in working pressures and a falling off in production. Natural decline is indicated by a falling off in production and an increase in gross gas factor.

At this point, a graph (Fig. 122) showing the characteristic curves of an air-lift installation working on a water well is shown. This graph was secured from the Ingersoll-Rand pamphlet describing their air-lift system and is used here with that company's permission. While it shows the result of a lift on a water well, it is believed that the same test methods and plots of results would serve nicely for the actual testing of the air-gas-lift installation in oil wells. Some of the units would, of necessity, be changed, but it is thought that if enough characteristic curves of oil-well lift performance could be assembled and studied, greater progress in the theory and in actual matter of design data would be made.

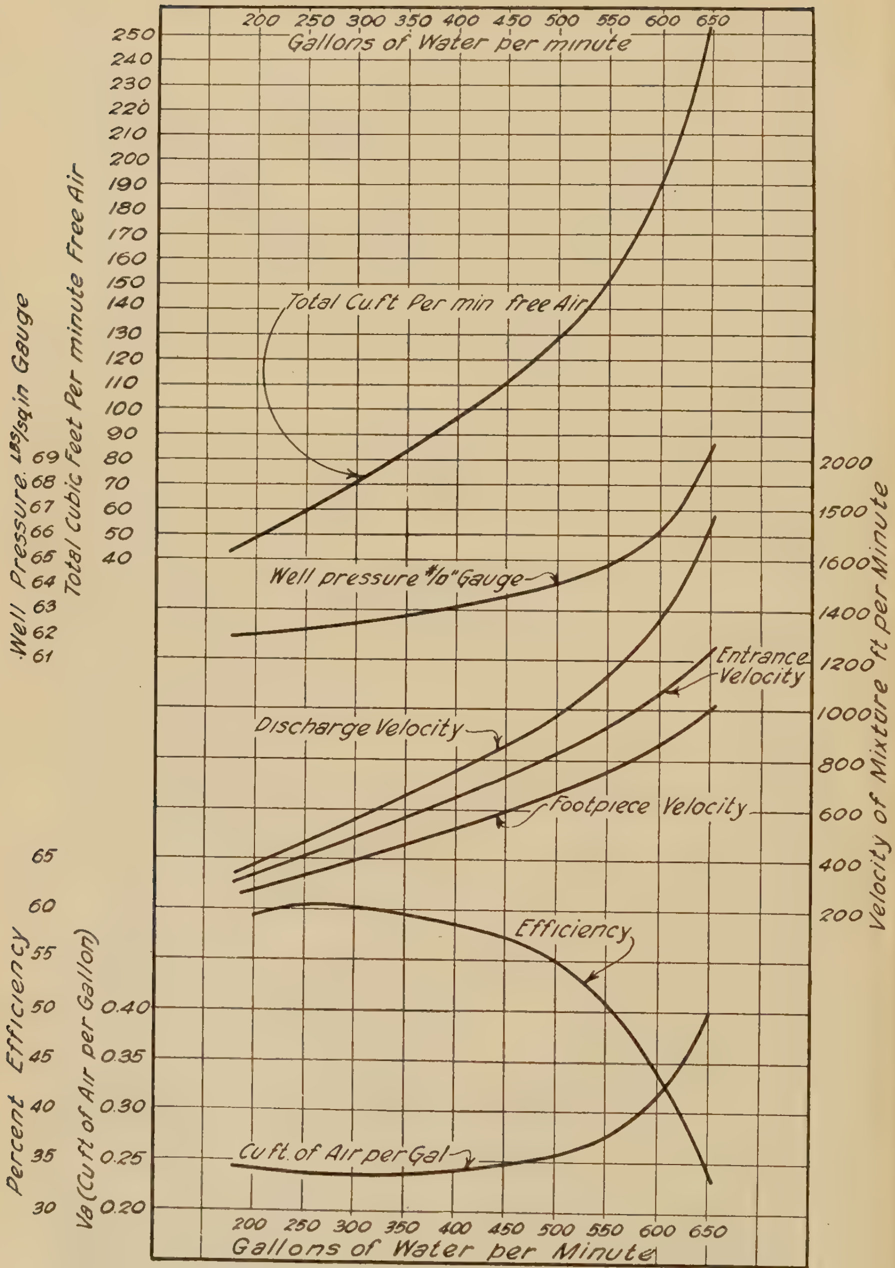

Fig. 122.—Plot of test data of air lift on water well. (*Ingersoll Rand Co.*)

The Economics of the Air-gas Lift.—The answer to the questions as to whether the application of the air-gas-lift principle makes money or loses money for the operator primarily and the industry secondarily are of the utmost interest to all concerned. There is no general answer; proceeding from a single well so equipped, through a lease with all its wells, through an entire field, through any geological or geographical grouping of fields, the answer may be yes or no depending upon the conditions found in the unit being considered and the skill shown in the installations themselves.

As stated before, the lift application is merely a method of pumping or producing a well which, if conditions are favorable, will produce more oil at a far lower cost per barrel than any other known method and, at the same time, conserve the energy of the gas or other oil-producing energy in the reservoirs.

Figure[1] 123 is reproduced here as indicative of one set of recorded experiences in regard to the above statement. But it must be remembered that all experiences are not similar; some published data show better results than the above and some poorer results and so on down to the total failures, of which little if anything at all is published but which, nevertheless, exist.

Some authorities state that the use of the lift application in the Seminole area broke the market. The writer believes that it would be fairer to state that the Seminole production broke the market through ill-advised haste and lack of all but enforced cooperation on the part of the operators, rather than the use of a very economical method of production, namely, the lift. It would be a serious error, without doubt, if the extended use of the gas lift, coinciding with new large producing areas, should cause an extensive amount of oil and its products to be consumed at a price materially below their cost over a period of recent years; a proper decision on this point should be made before the engineers and technical men can reach a decision on the economic points involved. But as the lift installation is controllable mechanically, which is rather more than can be said of the usual lease terms and royalty holders' desires, it is hardly believed that the application of the air-gas-lift principles in the actual installation should be credited with the overproduction and consequent low prices.

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[1] Scott, B. H., *Oil Field Eng.*, August, 1927.

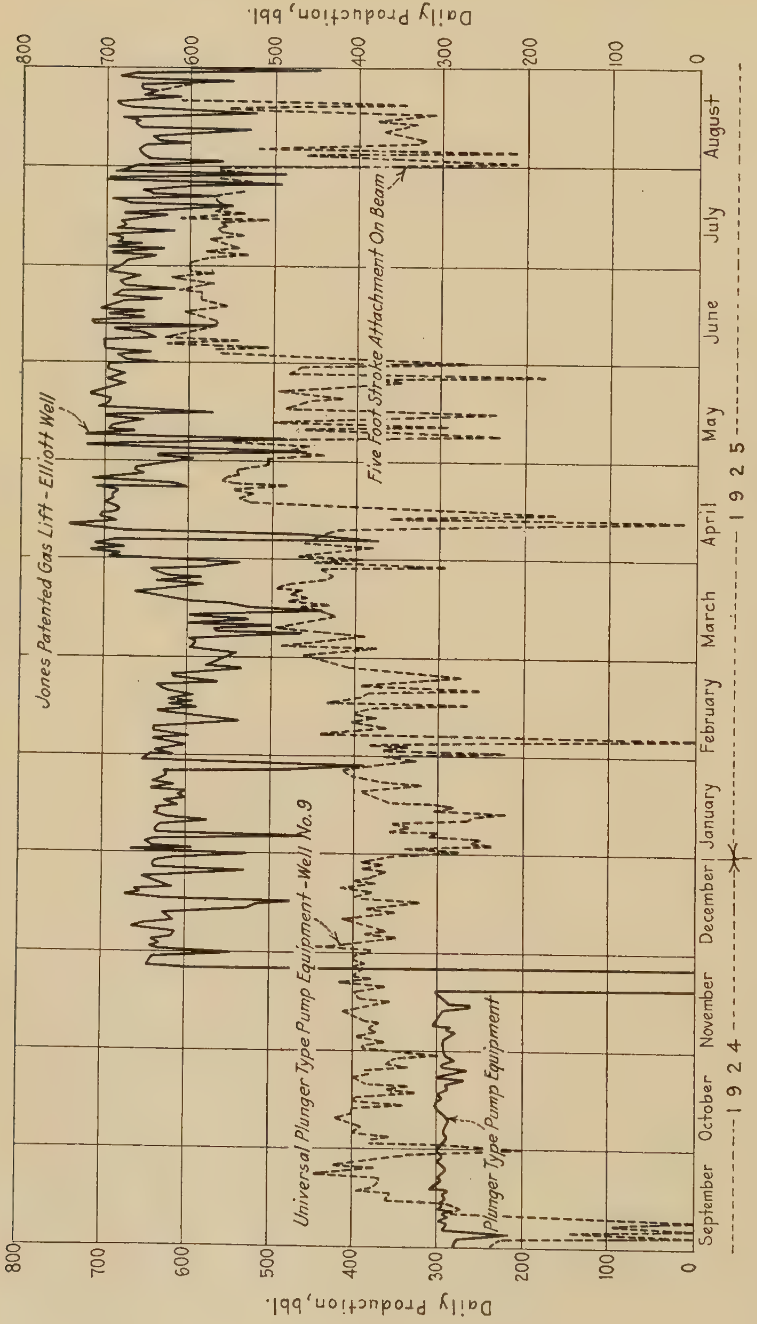

FIG. 123.—Comparative curves of gas lift and pumping installation.

At a meeting of the Mid-Continent Section A.I.M.M.E. Hollis P. Porter[1] made the following remarks on this point:

"The method has been condemned by several men prominent in the oil industry because enormous quantities of oil have been lifted to the surface of the ground from deep wells, resulting in overproduction and a corresponding low market."

"In defense of the air-gas lift, let me say that overproduction cannot be attributed to any modern mechanical improvement or to modern scientific methods being employed. The great trouble lies in the weakness in management of the business end of oil industry, which compels each individual producer to compete with his neighbor in an effort to capture his share of a migratory product. This kind of competition is not considered necessary for the protection of the public welfare. Its elimination by substituting cooperative methods would result in vast economy and would help the public and the industry alike. Methods of mining may well be cooperative without entering into combinations for the restraint of trade."

"The kind of competition forced upon the men who are bringing oil to the surface of the ground is like a cock fight, a destructive contest. It destroys the opportunity for economy, and compels methods in production which in turn force more rapid production. It shows that executive management has not kept pace with the application of new principles employed by the men in the fields."

"The result is overproduction and a low market. The cure is better cooperative methods between neighbors, and if adjustment laws are necessary, then such adjustment must come."

As stated by one writer:

"One of the assets to come from work in air-gas lift at Seminole is the education derived from its use there. Further, as Seminole is abandoned by these methods, its equipment will be transferred to other fields where its use has been slight heretofore, and installation of equipment in these various fields will further spread the knowledge of the methods toward perfection. While the idea has been exploited somewhat through the mid-continent that gas-air lift equipment will be abandoned at Seminole and thus the equipment will be charged fully against profit in production there, it was considered pretty generally among engineers that this will give other areas a chance to prove their reaction to the methods. And it will be these areas which will aid in paying for the equipment, certain percentages annually, according to company policies in charging off the equipment. There are numerous instances throughout the mid-continent where compressors and engines are in use which have been used in repressuring sands for more than a decade, and which are still giving first-class performance."

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[1] Porter, H. B., Cannot Charge Overproduction to Scientific Methods, *Nat. Petroleum News*, p. 75, Feb. 15, 1928.

An interview was published by N. O. Fanning of the *Oil and Gas Journal* staff which expressed the view that the air lift was responsible for the big overproduction. Excerpts from that published interview are given here to show that view point.

"One mistake the oil producer has made in the past few years is to spend $100,000 per well drilling down to 4,000 ft. when there is plenty of oil at 1,000 to 2,000 ft. in many accessible parts of the country. Perhaps it might be said the wildcatter is foolish to drill at all under present conditions. But we all know he will do it just the same, so what is the use of talking about it further?"

"The lower prices for crude will hurt the owner of the settled oil production which is the backbone of the domestic oil supply. The wildcatter will be jolted, but not discouraged. He will simply try for a bigger play, in the form of gusher production at shallower depths. And he will get it, without doubt, in East Texas, in West Texas, in New Mexico and in many other parts of the United States."

"Meanwhile, the air lift is increasing immediate recovery of oil 50 to 100 per cent in many large and small pools. The air lift will get out our next year's supply of crude in the next 6 months. The air lift is grossly uneconomic under present conditions because it decreases the underground and increases the above-ground reserves, the latter entailing a heavy immediate investment and an absolute loss of money. Artificial aids to oil recovery are only justified when they increase the ultimate yield from a sand and force heavy crude production when it is needed for an emergency."

"The air lift will probably mean a tremendous overproduction of crude this summer—worse than we have yet witnessed—and a terrific decline in production when we have stored up our oil above ground. It means instability because it means wider swings in crude-oil production and prices."

"The larger oil producers are using the air lift in cases where competition forces it, but beyond that they are paying more attention to building up stable reserves than to forcing current crude-oil production. They would rather spend $10,000,000 in building up a settled supply of crude than to build storage in a temporary flush field."

"For that reason, with a big oversupply of crude in sight some of the leading oil companies are buying acreage and putting in pipe lines in areas such as West Texas. The overproduction will not stifle activity in West Texas, nor will it discourage the building of pipe lines into that area, inasmuch as the district is known to be prolific of shallow-sand production."

"Perhaps the users of air lift will agree to discontinue this method of forcing unneeded production on the market; perhaps crude-oil prices will be cut further until more settled production is stifled. But then, again, low crude-oil prices may encourage the use of the air lift on the part of small producers."

Various articles have appeared in the technical press on this subject, some of the statements of which are given in the following paragraphs. The writers and publications in a few cases are unknown but the ideas that they have expressed are valuable; therefore they are added here.

Lewis[1] stated:

"Unquestionably the air lift will have a marked influence on the peak production of each new pool, its rate of decline thereafter, and the relation between flush and settled production, but in the writer's opinion the use of the air lift will prove to be inseparably involved with casing-head gasoline production, the application of pressure to the sands, and with cooperative operations in distinction from competitive operations of the fields."

"But it will be seen that these operations will necessarily result in coordination between air lifts, applying pressure to the sands, and gasoline making, and the compressor plant should be designed to apply pressure to some wells, to increase recovery, and to maintain rock pressure, to provide pressure to flow other wells, and to extract the gasoline from the air or gas returned from the wells to be recompressed for further use."

"The writer believes that, hereafter, definite plans will be made early in the life of each new pool for this combined operation and that it will soon be found that to work out these plans it will be necessary for the operators in the pool to cooperate in some effective manner, as only by cooperation can these logical steps be applied or full profits be obtained."

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[1] Lewis, J. O., Advantages of Unit Operation in New Pools, *Petroleum Development and Technology*, p. 177, 1926.

"It will be seen that the effect of air lifts on the rate of decline will be tremendously influenced by the manner in which these correlative operations are applied. If the lift is used solely as a competitive means, it will result as at Seminole with a much higher peak and a more sustained production at the peak but finally a rapid decline. There will, however, be a larger total recovery, but a larger proportion of the oil will be brought to the surface during the flush period and a smaller proportion left as settled production; however, the writer does not think that this will be more than a temporary phase in the revolutionary development of new methods of operation now going on."

"The writer believes that after the rock pressure begins to go down, pressure will be applied to the sand and the total production of the oil will be increased and the rate of decline slowed down so that there will be more settled production as well as total recovery. But it is believed that the industry will eventually go still further and will cooperate in some manner so as to regulate the production more in accordance with market needs, at which time the peak of production will be spread more evenly over a longer period of time, the field passing early in life from natural recovery to artificial pressure recovery methods."

Another writer stated:

"Widespread application of the gas-lift method of oil recovery promises to have an important economic influence on the oil-producing industry. Due to its superior lifting capacity and its effect in stimulating the rate of oil production in 'flush' fields, it is possible by this method to secure a larger part of the ultimate production of a tract of land during the early months of productivity than is possible by other means. The average period of deferred realization of income from a producing property is thus materially reduced and the present day value is therefore increased. In making oil property appraisals, the shorter period of realization possible by the use of the gas lift must certainly be taken into account. The shorter economic life of oil properties exploited by this means may materially alter the well spacing and development programs in newly discovered fields."

"When a gas lift is once installed, due to its low operating cost, it is probable that its use will be continued until a well becomes a very small producer, say 5 or 10 bbl., unless the equipment is desired elsewhere."

"The equipment will be paid out, due to the increased recovery in the earlier stage of the well's life, and it may be more economical to continue to use it than to assume additional expense in equipping the well for the pump. However, I believe it is perfectly feasible, and probably will be the best course of action, to place such wells on the pump when their production becomes very small. When the pool is no longer a commercial producer on the pump, pressure restoration or water drive may be resorted to if the formation is favorable."

"If we assume, on the contrary, however, that the ultimate production in either case will be the same, then if we should double (with the gas lift) the amount of production in the first year of a well's life, it probably will be equal to the loss in production over a period of possibly 10 years in the latter stages of the well's life."

"The increase in production during the first year of a well's life due to the gas lift would be recovered at a far less cost than an equal amount of production in the latter part of a well's life. The saving in lifting cost, plus the interest on this additional oil produced in the first year of a well's life, when considered over a 5- or 10-year period, would be a very considerable item."

"Granting then, for the sake of this discussion, that the ultimate amount of oil recovered would not be increased, at least the total amount of oil taken out would be produced at a much less cost with the consequent result that the consumer would be benefited by a lower price for petroleum products."

One writer states:

"On this question I would point out the importance of the economic factor. If 80 or 90 per cent of the normal yield of a well can be recovered in 8 or 9 months of flowing with the gas lift, will the companies be able to afford the expense of 5- or 10-years' pumping to recover only the last 10 or 20 per cent? Similarly, if the engineers decide that the alleged 20 or 30 per cent now recovered from the wells by the customary practice of flowing and pumping can be increased to 40 or 50 per cent by the use of the gas lift, the incentive for the water drive as used at Bradford, or the air pressure as used at Marietta, will be materially lessened; and the gas lift may, therefore, resolve itself into a quick method of skimming our reserves cheaply to produce a profit even at current prices."

"If we can take from the ground an average of 80 per cent of the newly developed reserves during the first year, and during the second year recover only the 10 per cent average that might normally be applied to the well's fourth year, we will have an enormous drop in the production of newly discovered areas, to which reference has been made as the 'backlog of old settled production.'"

Another writer explains the point in regard to the Seminole area as follows:

"The Seminole field in Oklahoma is the first major producing area in which the air-gas lift has been tried on an extensive scale. Its operation there has been highly successful and approximately 60 per cent of the production of the greater Seminole area is being brought to the surface through the use of gas or air to lift the crude. Data compiled from actual operation of many wells in that area, being produced by air or gas lift, show the commercial production of a well produced with air or gas lift is procured within a period of 10 months. At the end of 10 months, wells produced by this method are abandoned [?], all the crude possible to procure commercially having been brought to the surface."

"Use of the air- or gas-lift system in producing crude oil results in bringing the oil to the surface far more quickly and in much larger volume than the older methods. While the practice has not been employed long enough to arrive at any definite figures as to ultimate production, decline curves made on the performance of many wells in the Seminole area prove to the satisfaction of many persons in close touch with the situation and who have made a close study of the subject that a greater quantity of oil is recovered through use of the air or gas lift than would have been recovered through pumping and swabbing. This refers only to the Seminole area, as each field has its own peculiar characteristics which affect the use of the air or gas lift, and data are not available on other areas."

"Consequently, the petroleum industry is now experiencing the situation of obtaining the maximum recovery from a new field within a comparatively short period of time and will not obtain a settled production from that field over a period of years as would have been the case had not the air- or gas-lift system been installed. This means great quantities of crude oil were brought to the surface quickly and, in the case of Seminole, during an average period of 10 months, instead of being spread over a period of 3 or 4 years."

"Summarizing the change in conditions brought about through operation of the air-gas-lift system, crude oil is being stored now which under former practices would have been brought to the surface over a period of years as settled production. These stocks must cover the period usually taken care of through settled production from big fields, for operation of the air-gas-lift system will bring all the crude available to the surface quickly and there will be little if any left in the form of settled production to be procured during years after the field has passed its peak."

The life of an oil well in Seminole operating on the gas-lift method of production is, of course, governed by the usual variable factors. It depends somewhat upon the amount of recoverable oil per well in each of the producing fields. This ultimate recovery factor cannot be arbitrarily determined. Some operators estimate that the gas lift is removing in 1 year an amount equivalent to that which the pump would produce in 4 years. Average life of a number of wells has been 10 months to 1 year. This again is influenced by water encroachment. Engineers differ as to the influence of the gas lift regarding water, some maintaining that the lift deters water encroachment in its application, while others affirm that the gas lift hastens the encroachment of water and lessens the productive life of the average well. Some companies have abandoned wells as nonproductive due to low yield of oil or to the increase in water production. Since there is no method of determining an oil well's ultimate production until it has yielded it, then this question of total production under gas-lift methods as against other methods is difficult to answer. Many operators maintain that the break is about even, and that gas-lift methods in Seminole are producing the equivalent amount of oil in about one-fourth the time that a given well would produce on the pump. Some wells in the Seminole area, where hole conditions are right for pumping equipment, have been taken off the pressure flow and converted into small pumpers.

J. L. Dwyer[1] summarized the economic situation as regards the lift application as follows:

"There are dozens of different phases to be considered regarding the effect which air-gas-lift equipment will exert upon the major oil fields of the future, and probably one of the most important, and one which will have the greatest bearing upon the stability of the future crude markets, is the unusually large average production per well which is maintained not only during the time when a few wells are producing in a new pool, but all through the period of intensive development, and for a considerable time after the pool has touched its peak of production."

"There is this salient fact to be gleaned from a study of the air lift in this connection, that the oil fields of the future will not require the number of wells to maintain a production which places them in the category of major pools, for the lift will be capable of sustaining the output of the wells after they are drilled in."

"In the major pools of the past, the average production per well has registered a sharp drop soon after the first group of wells has been completed. The Tonkawa Wilcox sand pool attained its peak when 21 wells were drilled in. The Wewoka Wilcox sand operation near the city of Wewoka in Seminole County touched its highest figure when 14 wells had been completed, and while both of these fields had some air-lift equipment, its use was far from general. The Tonkawa deep field especially had the lift applied long after the excitement had subsided."

"The point it is desired to emphasize in considering the use of the air-gas lift in operations of the future is that we shall not require the large number of wells to make pools capable of producing 100,000 bbl. daily or better, for instead of experiencing the normal decline which the majority of the fields of the past have witnessed, the air lift will keep the production from slipping, and although there is some doubt as to whether or not this equipment will result in a greater ultimate production per acre, it will at least speed up the wheels sufficiently to throw greater quantities of crude on the market in a much shorter period of time than has been the experience in former fields."

"Considering the flush state of any pool, an average production per well of 300 bbl. may be considered a respectable figure, and if the pool maintained this average until the drilling campaign was over it was reckoned a good average."

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[1] Dwyer, J. L., Air-gas Lift Permits Big Well Average, *Oil and Gas Jour.*, p. 33, Aug. 18, 1927.

"Compare this figure with the average output per well of the Earlsboro average [Fig. 124] which was originally high, owning to the discovery well having an initial output of 8,900 bbl. The second and third wells to be completed in this pool also had good production, leaving the average still high. The effect of drainage upon the wells did not result in a drop of average production until

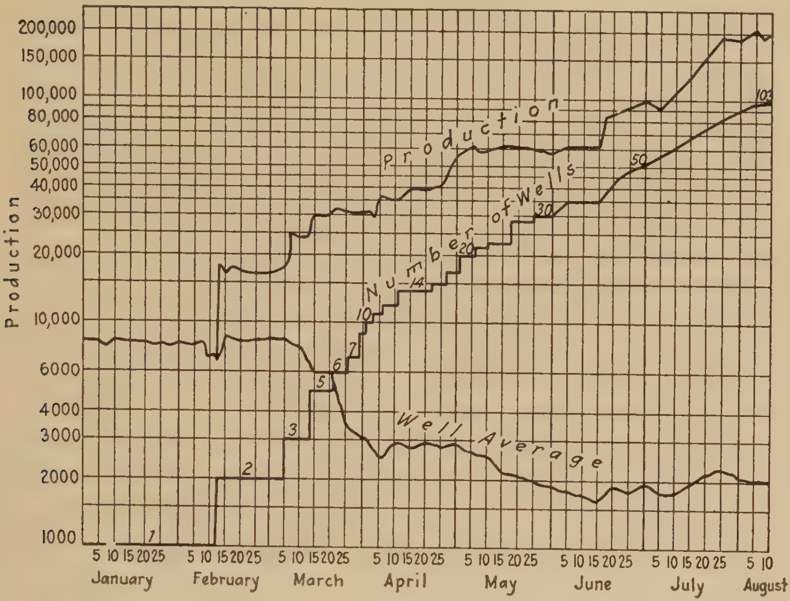

FIG. 124.—Production, wells and average well production of the Earlsboro pool. (*Dwyer.*)

the fourth well in the pool was completed, and from that time on the introduction of the air lift was responsible for the performance of the averages."

"Earlsboro did, however, have a smaller number of wells on the air-lift method than Bowlegs, which had a comparatively short flowing life for its wells. For the past 3 months [May, June, and July, 1927], however, the average output of the Earlsboro wells will run very close to the 2,000-bbl. mark. It dropped below this figure during the month of June owing to limited output of 5 new wells. At this time the number of wells completed ranged from 30 to 35, and when the thirty-fifth well was completed, additional territory in the north and northwest extensions of the pool brought the average up again, and it has since hovered close to the 2,000-bbl. mark."

"The Bowlegs pool [Fig. 125] with the greatest number of air-lift wells of any of the Seminole pools is probably more indicative of what may be expected from the operation of the lift in the future, because this pool owes its prominence to the lift exclusively. A very limited gas pressure caused a flowing life of very short duration for the Bowlegs wells and the lift was applied to wells in this field within 2 weeks after they had penetrated the sand."

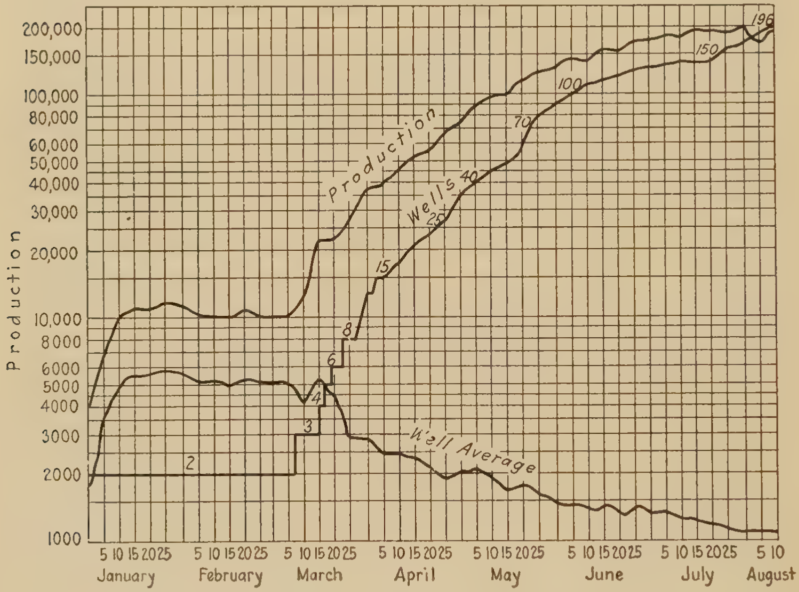

FIG. 125.—Production, wells and average well production of the Bowlegs pool. (*Dwyer.*)

"During the period when there were 2 wells at Bowlegs, the average followed the production remarkably. When the fifth well at Bowlegs was completed the decline started and the output per well dropped until Mar. 25, 1927, at which time the decline per well was arrested by the installation of several air-lift plants which steadied the average per well temporarily but could not at that period maintain it. On June 1, the pool was about 6 months old, and had 90 completed wells which showed an average of 1,500 bbl. per well, a very unusual figure for this number of wells at this age of pool. On this same date, the Earlsboro pool had approximately the same age and showed an average of 1,900 bbl. per well from 30 wells. The higher figure of the Earlsboro pool was caused by the large natural flow which was general in that pool. The Bowlegs averages may be considered representative of the use of the air lift, and will very likely be employed in computing future operations of the lift."

"The Greater Seminole area has had many peculiarities. There was a noticeable lack of gas pressure, and a very delicate pressure was observed in flowing wells. In some wells in the north end of the Seminole City pool this delicacy was particularly noticeable. One well was flowing 1,500 bbl. when it was decided to run the string of clean-out tools into the hole for the purpose of agitating the flow and increasing it. The tools had been lowered only 600 ft. when their entry caused the well to stop flowing entirely. When the tools were pulled back out of the hole, the flow revived itself, and the production was the same as before the well stopped. In another instance in the same part of the field, a string of tubing was being lowered into a well which was flowing 800 bbl. daily. The string was lowered to about 1,000 ft. when its entry caused the well to stop flowing. With this condition, it has been necessary to use the greatest care and judgment in handling the production of the Seminole wells, and no other field known to the industry has necessitated so much study of individual well performance and record. In this field each well is a problem in itself, and the rules which ordinarily may be generally applied to an entire field would have proved disastrous at Seminole. Tanks and connections, tubing and gas separators, flow lines and their angle of position, each has a distinct bearing upon the output of the Seminole wells, and there are over 50 different hook-ups for wells in the field, each designed to suit the requirements of various wells."

"The application of the air lift to oil fields of the future will have a much different story to tell for numerous localities where showings of oil have been found. In the annals of the fields, there have been thousands of wells which have had columns of oil rise to varying heights in the hole, and have not had sufficient gas pressure to flow the oil. It is cases such as these which will be the most affected by the lift in future operations, for when the oil exists in sufficient quantities to rise in the hole, the lift may profitably be brought into use, and substantial production recovered."

"Past years have displayed many instances where wells have been recorded as '800 ft. of oil in the hole.' Such wells have usually turned out to be good pumpers which started fields or small pools which slowly developed and expanded if price conditions were favorable. Reasonable time was permitted to elapse before the offset wells were started and if the pumper held its production at a profitable figure which would ultimately cover the cost of drilling, then one or two offsets were started, and the field eventually became a good stripper proposition which paid the investment and left a small but regular profit."

"In the case of the same field today, wells having 800 ft. of oil in the hole may be successfully put on the air lift, and their output may possibly run to 1,000 bbl. by its use. The offset wells will be started immediately, and a rapid development may be witnessed in localities where formerly the pumping wells produced the output."

"The use of the lift may not result in more production for the future, but it is certain to mean more oil from less wells in active territories."

CHAPTER XVII

THE AIR OR GAS LIFT (*Continued*)

Notes on Installation.—The notes on the practical installations met with are assembled here under the subtopics as shown in the index. Many notes on the practical points of the installations have been given under the various subjects treated as entering into the immediate subject better than into this general subject. The following notes and subject matter have been collected from many sources. Some of the quotations are from articles the names of the authors of which are unknown to the writer, but which are used in the belief that their statements are of value to any one interested in this subject. One series of articles by Brundred[1] is especially worthy of notice and will often be quoted.

The one most important point in an air-gas-lift installation is to prevent leakage. Regardless of the type of hook-up, efficiency of operation of the gas lift requires that the maximum volume of gas introduced be put to useful work. Gas-tight tubing and casing are, therefore, of very great practical importance.

If there are leaky tubing joints along the string above the intended level of inlet, gas will pass from the casing space into the tubing through those points and be largely wasted. Likewise, if there are leaky casing joints, perforations, etc., gas will pass out of the well through such leaks without doing any work at all. The most rigid precautions must be taken to eliminate all possible leaks because they represent a serious loss of money in any case and they may often entirely defeat the operation of an otherwise excellent gas-lift installation.

The plan of this section will be to start with plant installation and go through the system point by point, taking in order the items of distribution system, the control, manifolding, well-head connections; traps and separators, and surface flow lines.

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[1] Brundred, L. L., *Oil Weekly*, Nov. 11, 18, 25, 1927.

Plant Layout.—As stated by Pennington:[1]

"Air and gas compression is a subject covered fully in detail and at length in current treatises. Designers of compressors know how to build the machines for sustained operating periods; to proportion the cylinders with correct ratios for efficient work and for safety at high pressures; to cool the discharge without difficulty; to operate the machines at high speeds to secure capacity; and to fuel the engines economically."

"The problem of power for air lift, however, is much like the drilling power problem; the requirement is maximum during flush production, but when all wells are drilled, the quantity of air, and the power is reduced; the requirement for flush production is always too large for settled periods."

"The Mid-Continent practice of installing plants that may later be used for natural gasoline plant manufacture, and of recovering natural gasoline while blowing wells, is ideal, for the high-pressure air cylinders may be replaced with cylinders operating at lower pressure, single stage, at the proper time. Present practice is to install two-stage machines, with maximum working discharge of 1,000 lb. for starting wells. Operating at 200 to 400 lb. discharge pressure, cooling the gas between stages and after the final stage, means that a simple gasoline plant of the compression type has been built. Controlling the design so that cooling coils may be used for absorption plant, and erecting absorbers and stills afterward, is excellent engineering. A few are doing this now in the first instance."

"For serving this purpose, it would seem good engineering to install sufficient large, heavy machines to use as gasoline plant equipment when flush production ceases, and to supplement this type with the lighter multicylinder engines of lower cost for flush peak work."

"At Seminole particularly, where there is not as great quantity of gas as was found at Tonkawa or at Burkburnett, the great numbers of compressors installed and being installed will provide for more capacity than necessary for settled work after flush production has subsided, and a majority of these units will necessarily be shut down and moved elsewhere at considerable expense."

"The multicylinder engine, possessing extreme portability, together with a multicylinder compressor, offers the advantages of low cost and quick installation, equally as low operating cost and reliability. For this work, the writer prefers the six-cylinder engine of about 125 hp. directly connected to a two-stage high-speed compressor, both mounted on an I-beam base. This unit can be hauled to the field, slid off on timbers and started in a few hours. Due to higher speed and lighter weight, this type of compressor offers the lowest capital installation cost."

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[1] PENNINGTON, HARRY, Lift Efficiency Depends upon Skill in Design and Operation, *Oil Weekly*, p. 76, Aug. 19, 1927.

Advantages of Different Types of Prime Movers in Lift Work

	Advantages	Disadvantages
Multicylinder gas engines of the higher speed type....	Low or no fuel cost Lowest cost Portability Quick erection Low foundation cost Low operating cost	Lesser life than the larger single-cylinder engines Low flexibility
Gas engines of the heavier slower speed type........	Low or no fuel cost Long life Low operating cost	Greater cost than multicylinder engines Low flexibility Slower erection Non-portable
Steam engines and boilers...	Extreme flexibility Moderate boiler life High overload capacity	High fuel cost Greater foundation cost Slow erection Non-portable
Electric motors...........	Low maintenance cost Low erection cost	High power operating cost Must be on power line Interfered with by transmission troubles Fire risks

"Mobility or portability of equipment is an important factor. It has been so especially in the case of Seminole operation this past winter. Road conditions in this particular area have been particularly difficult, and the handling of the heavy type of equipment has been especially burdensome, while the handling and placing of the lightest equipment has not been so fraught with difficulty, and has probably been accomplished at some lesser expense."

"Contrary, probably, to the conception prevailing in the outside world, the oil industry is the most conservative of any in its expenditures for the equipment it requires. Selection of its equipment is based almost invariably on the most conservative and careful study, looking to efficiency and effectiveness of that equipment. In view of this fact, the industry has seen, due in part to stressful demands made on the manufacturers of machinery required and in part to the condition of roads for transportation as above mentioned, a rather extraordinary innovation in the type of equipment which has been applied in the Seminole fields in the plants built for the purpose of pressure-flowing operation. It was found in the early operation of some of the installations that pressures required to break the column head of fluid ran as high as 800 or 900 lb. per square inch, and this limit is not unusual, as encountered in the method generally. As a consequence, naturally the selection of compressor equipment must call for the heft necessary to this end. Two general types of compressor equipment have been employed, and this relates wholly to displacement capacity per unit. The larger type and capacity is low-speed equipment; the small type, as related to displacement capacity, is of the high rotative speed type, and the usage of equipment seems to be fairly evenly divided between the two types. The prime movers called into usage to handle these compressors are gas engines and public-service electricity, with a few noted exceptions wherein oil and steam engines which have been salvaged and transferred from other operations are also being used."

"The innovation above mentioned is the application of light, high-speed multicylindered gas motors. This break from the old lines of standards has the earmarks of novelty, in view of the fact that a great many of these motors have been installed and are now operating with apparent success. It remains to be seen, of course, how this departure will ultimately succeed. Motors ranging in capacity from 75 to 100 hp. have been installed in flocks. Their rotative speed runs as high as 1,200 r.p.m., and without desiring to pass heated judgment, the writer's opinion would be that the maintenance of these high-rotative speeds in prime movers will involve high-maintenance cost. The mobility, however, of this light type of equipment, necessarily speaks strongly in its favor. Always the element of time is of absolutely primary importance in the recovery of flush oil from new wells.

The matter of a difference of a very few days in the production of large wells can account for expense to any measure almost without limit, which may be applied as effectively as is the case in the method of successful air lift."

Landreth Production Corporation has the largest plant in the Church and Fields district, on its strip lease. As described by A. R. McTee:[1]

"This installation is made up of six 9½ by 4 by 10 Ingersoll-Rand compressors with starting pressures of 1,000 lb., and continuous operating pressure of 500 lb. There are also six 11 by 5 by 10 compressors with 500 lb. starting, and 300 lb. operating pressure. Short belt and idler drive is used, and the compressors are driven by 75-hp. squirrel-cage General Electric induction motors."

"There is a main air header running the length of the lease, with the plant in the center. Laterals take off from the header to individual wells. The header is telescoped; 8 in. at the plant, 6⅝ in. for three locations, and 4 in. the rest of the way. Foxboro controls are installed on each lateral. The well hook-up is the National Supply Company's standard Christmas tree, arranged for rocking, with blow-off to the pit. Christmas tree connections are 3 in. Three-inch tubing is used on wells making above 600 bbl.; below 600, 2½ in. is used, and one 2,000-bbl. well will have 4-in. tubing."

"A 2-in. high-pressure line runs to all wells tied into the plant so that several machines can be put on one well to kick it off. This relieves the main header of excessive pressures. The wells are produced through the tubing."

"Below is given the production record on four of Landreth's wells for one day, which is typical for the time the wells have been on air:

Well number	Flowing pressure, pounds	Injected air, cubic feet	Production, barrels
1	190	140,000	525
3	215	510,000	1,050
5	185	312,000	425
6	180	353,000	480

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[1] McTee, A. R., "Air and Gas Lift Still Experimental in West Texas," p. 56, *Oil Weekly*, Aug. 19, 1927.

"Well No. 8 is flowed direct to storage, with two compressors boosting it at a pressure of 210 lb. No meter is on the well. It makes approximately 880 bbl. of oil daily. The well flowed naturally for a while after completion, but declined until it finally stopped. Then it was shot, after which it made 600 bbl. After it went dead a second time, it was put on air and has been kept at about 880 bbl. since, which is near the initial flow. Number 3 well was dead when put on the air. It is now making more oil than any other of Landreth's air wells, and is also being held near its initial yield. The first day on air, it made 1,200 bbl."

"Separators on Landreth's wells are set as close to the wells as possible, and at such height to enable flowing by gravity to the field tanks. Tubing is set from 30 to 50 ft. off the top of the sand. Starting pressures on Landreth's wells range from 500 to 650 lb."

"Production on the Landreth lease has been increased by air, but no check has been kept of the gas-oil ratio. It is planned to equip future wells with apparatus to measure the gas, so that within a short time this company will know the amount of gas conserved."

In the building of the large permanent plants, of which there are several in the field, the manufacturer of equipment has aided the plant operators. Factory fabricated materials of all kinds are now available which can be assembled quickly after they arrive in the field. Some remarkable records have been made in the construction of these plants.

Regardless of the type of equipment, salvability has been the aim of the manufacturers. Due to the peculiar operating conditions in the field, the manufacturers have never been able to gage the probable settled gas supply available. Six months or a year from the time of installation, it will probably be necessary to change the original capacities of the plants, with a possibility that some, at least, will find it necessary to move their equipment to other fields. Due to that fact, manufacturers have designed their equipment so that it could easily be added to or substracted from with minimum of loss.

When the air lift is used, usually it has not been feasible, commercially, to recover the gasoline from the gas and air mixture as it comes from the well along with the crude oil. This is largely due to the fact that the air and gas mixture under pressure is hazardous to handle in the manufacturing operation. This fact, in several cases, has necessitated special care in the operation of the plants, because there was constant danger, when connection was made to several wells, that the gas supply would be contaminated with the air.

In cases where the gas lift is used, the manufacturers have been required to take care of large volumes of gas. The practice is to return the residue gas from the plants to the wells, where it is recycled in the gas-lift operation. The recycled gas is then returned to the plants for the extraction of the gasoline. While this tends to increase the volume of gas, at the same time it reduces the gasoline content.

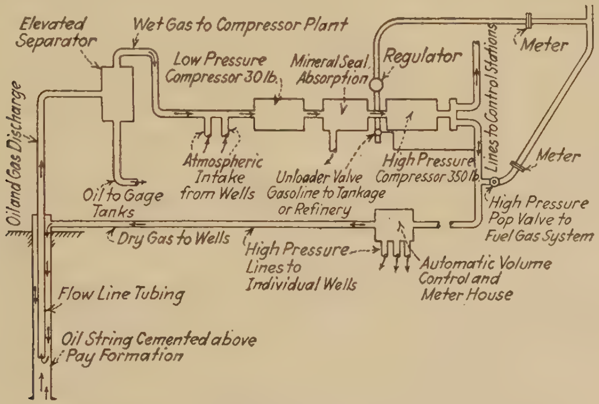
Elevated Separator
Wet Gas to Compressor Plant
Low Pressure Compressor 30 lb.
Mineral Seal Absorption
Regulator
Meter
Lines to Control Stations
Oil and Gas Discharge
Atmospheric Intake from Wells
Unloader Valve
High Pressure Compressor 350 lb.
Meter
Oil to Gage Tanks
Gasoline to Tankage or Refinery
High Pressure Pop Valve to Fuel Gas System
Dry Gas to Wells
High Pressure Lines to Individual Wells
Automatic Volume Control and Meter House
Flow Line Tubing
Oil String Cemented above Pay Formation

Fig. 126.—Flow diagram for gas lift in connection with gasoline absorption. plant secycling method. (*Bennett and Sclater.*)

This gas-lift operation is directly responsible for the wide application of the compressor-type plants in the Seminole field. In some cases, the gasoline manufacturers have been asked to furnish the gas at 200 to 300 lb. pressure to operate the wells by the gas lift. In doing this, it is generally necessary to remove as much gasoline as possible through condensations of the heavier ends. Even in cases where the residue is simply boosted back to the leases at low pressures, certain manufacturers have believed the compression method of gasoline to be more economical than the usual oil-absorption method. In other types of installations, the low stage of the compressors is used to furnish the pressure necessary for the operation of the oil-absorption division of the natural gasoline plant, while the high stage was used to compress the gas to the pressure required for well operation. Still other plants are operated as oil-absorption units.

Every manufacturer has been compelled to work out the solution of his own problem; and in doing so, practically every method of plant operation has been utilized. The main idea has been to cooperate with the producing companies so that they could obtain the maximum production of crude oil. In carrying out this policy, if any sacrifices in efficiency had to be made, the natural gasoline manufacturer, rather than the crude oil producer, has made them.

The natural gasoline industry has long practiced the scrubbing of gas prior to compression. This cleansing of the gas is of much importance and is generally recognized now by gas-lift engineers and operators. Much trouble with compressor valves, pistons, etc., is avoided now, which was incurred with some earlier installations and loss of running time and expense of repair is eliminated by the installation of simple scrubber tanks which guard against the entrance of sand and scale into the machines. Plants running on recycled gas coming directly off the separators find that by installing scrubbers the possibility of getting liquid into the cylinders, where it might easily cause serious damage, is avoided. The tank must be of sufficient size so that the gas upon entering the tank will be sufficiently reduced in velocity to drop any entrained fluid or scale or other foreign matter before reaching the compressor. Plants running on air are installing efficient air filters on the compressor suction for the same reasons.

A large number of compression plants are constructed in such a manner that they can be readily switched from the compression of natural gas to the handling of air. Such plants must have two manifolds for proper distributing, and most of them have the lines painted in such a manner that the gas system is easily kept separated from the air lines. When these compressor installations are handling natural gas they are productive of natural gasoline because of the pressure necessary to operate the gas-lift systems and the richness of the gas. Such equipment as accumulator tanks, etc., from which the condensed gasoline is blown to storage is, therefore, provided when the plant is erected.

Figure 127 shows a combination compression gasoline and flowing plant consisting of four 165 hp. Cooper compressors located in the Earlsboro field.

The compressor plant should be placed near the gasoline plant because it is more economical and efficient to handle high-pressure gas over a distance than low-pressure gas.

In plant construction, right-angle bends have been eliminated as much as possible by using 45-deg. bends or by bending the pipes in a special machine. Each plant is different in detail, the difference in construction being due to the engineer in charge. Companies are building several kinds of plants, experimenting in each case with respect to construction, equipment, and operation with the idea of standardization in mind. When that point is reached, costs of construction and operation will be greatly reduced.

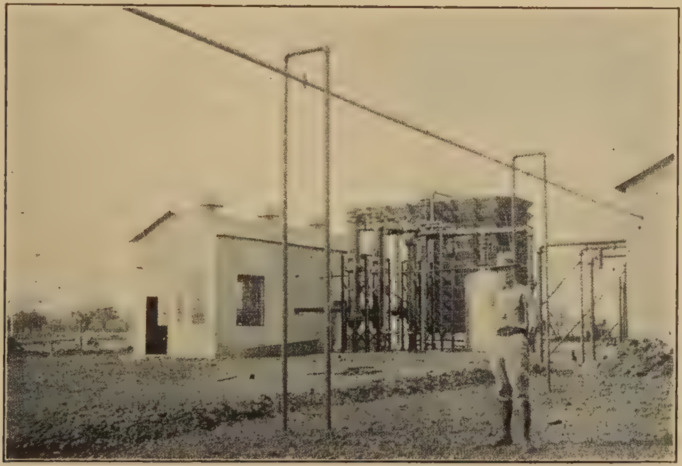

Fig. 127.—A typical small combination compression, gasoline and flowing plant.

In Whealton[1] and Townsend's book the following subject matter appeared:

"The site selected for the plant depends upon several factors, but the factor to be given greatest consideration is the location with respect to the wells to be served. If the plant is to serve several wells, manifestly it should be located so that the lines to the various wells will be as short as possible, thereby eliminating additional cost of longer lines, as well as keeping friction to a minimum."

"The number of wells handled from one central location varies with the different companies, some companies preferring to put the units near the particular wells to be immediately served, with the idea of putting in future units at different locations as indicated by future wells. The trend of practice at the present, however, is toward the centralization of as many units as possible in one location. This practice tends toward more economical and better supervision of the machinery. One plant to a 40-acre or to an 80-acre tract is customary, although sometimes 160 acres are served from one location."

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[1] "Recovery of Oil by Air and Gas Lift," Whealton & Townsend Inc., Tulsa.

"Other factors include residue gas source when the plant is running as a gas instead of air lift; source of water supply; fuel supply, etc. The character and slope of the ground is of importance and a level location is to be preferred in order that foundations may be put in as economically as possible. A site that has drainage away from it is highly desirable."

"With the type of machines in general use for this service, the nature of the soil is of small import as machines are in many places operating satisfactorily on wood timbers settling on sand footings."

"In laying out a compressor plant regardless of the number of units at first installed, provision should be made for the enlarging of the plant as the need for more machines makes this necessary. All of the headers both intake gas, discharge gas, water and fuel headers should be so laid out that on one end or the other all of these can be extended to care for additional machines without tearing out any of the existing installation. Some companies have so laid out these headers that extensions can be made from either end."

"Whether using gas engine, oil engine, electric motor, or steam for power purpose, it is necessary to have a cooling tower of some sort for the cooling of the compressor jacket water for most efficient operation of the compressor plant during hot weather. The number of machines and motive power used governs the size or design of cooling tower. For a small plant a set of board timbers over a wood water tank is generally sufficient."

"A point which has been generally overlooked in the rapid growth of this phase of the industry and the promiscuous installation by those unfamiliar with the requirements has been the safety features not only called for by our state laws and insurance companies, but by the dictate of good judgment. A guard rail is required around each exposed moving part such as flywheels, belts, etc. If this guard is placed 15 to 18 in. from moving part, it should be 42 in. high above floor level with one strut 21 in. above floor; vertical supports are necessary not over 8 ft. apart. If however, guard is placed closer than 15 in. to moving part, it should be 6 ft. high and enclosed with wire mesh. The supporting rails should be not less than 1¼ in. pipe, 1½-in. angle iron or 2 by 4-in. lumber. In the case of electric substations, a fence 6 ft. high should enclose all parts of the substation at sufficient distance away to prevent anyone reaching through the fence to any of the apparatus. All electric wiring should be encased in vapor-proof conduit either controlled by vapor-proof switch or by switch outside the building. Compensators and other devices should be installed if inside the building in such manner that the danger of an explosion from a spark will be eliminated."

"It has long been the practice of the natural-gas gasoline industry to place scrubber tanks on the incoming gas lines to compressors and it is now becoming more general practice to use them in connection with gas-lift installations. Much trouble with compressor valves, pistons, etc., could have been avoided in a number of the earlier existing plants which has caused loss of running time and expense for repair had this simple precaution against the entrance of sand and scale been taken. Where the plant is running on recycled gas coming directly off the gas and oil separators, a scrubber tank also will minimize the possibility of liquid getting into the cylinders where it might cause serious damage. The tank should be of sufficient size that the entering gas will by its reduction in velocity drop any entrained fluid or scale in the tank before entering the compressors."

"With a plant running on air, an efficient air filter is desirable on the compressor suction in which case a scrubber tank is unnecessary."

"The pipe and connections on the high-pressure discharge should be given special consideration to see that proper strength material is used and installed in such a way that expansion and vibration strains will not cause a break in the piping."

"It is customary to use 1,500 lb. working pressure, 3000 lb. test valves and fittings throughout with extra strong pipe or tubing. Quite often the connection is made flexible by the use of ball joint fittings near the compressor."

The following article[1] on one of the Tidal Oil Company's plants gives some interesting and instructive data:

"Tidal Oil Company's flowing plant on the University F Lease, Church and Fields pool, consists of six 80 hp. single, four-cycle Western gas engines, belt driven with a short center idler belt drive to 10½ by 4¾ by 12 Worthington straight-line compressors. These have a discharge capacity of 288,000 cu. ft. per 24 hrs. at 500 lb. Compressor speed is 260 r.p.m."

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[1] McTee, A. R., Air and Gas Lift Still Experimental in West Texas, *Oil Weekly*, p. 57, Aug. 19, 1927.

"Physical condition of the gas used in the engines gave trouble, but changing the mixing boxes on the engines remedied this."

"The plant is being enlarged by six Ingersoll-Rand duplex 11 by 5 by 12 compressors, driven by 75 hp. General Electric induction motors using 440-volt current. These compressors operate at 300 lb. pressure."

"Portability is a feature of this extension to the Tidal plant. Inasmuch as production in the Church and Fields area is from lime, there is much conjecture as to its length of life, and the company is building the plant so that its salvage value will be as high as possible. The compressors and motors are being set on heavy timbers and securely bolted."

"Pouring concrete in the Church and Fields pool is also expensive, the floor of one small plant costing above $8,000, and Tidal believes the new plant will operate as well as if it had the floor."

"Sand filters are used on both the engines and compressors at the Tidal plant."

"Number 2 well on the lease has been on air the longest. When air is taken off, the well stops flowing. It operates at a pressure of approximately 260 lb. About 220,000 ft. of air is required to flow the well. Recently the air volume was boosted to 400,000 ft., with a resulting increase in production amounting to 100 bbl. The gas-oil ratio is about 450 cu. ft. Before putting the well on air, the ratio was 670 cu. ft."

"On the same lease, Tidal is flowing wells No. 1, 3, 4 and 5 by air. The drop in gas-oil ratio is said to be comparative with that in No. 2. These wells do not stop flowing entirely when air is taken off, but they then flow by heads."

"Tidal's control apparatus consists of 500-lb. orifice meters on the air lines. To determine whether or not the wells are flowing steadily, a recording pressure gage is set on the flow line from the well. Gas from the well is measured by the Pitot tube method."

"Compressors in Tidal's plant are piped so that any number can be put on one well."

"Starting pressures on the wells run as high as 650 lb. Worthington compressors are used to kick the well off and they are then switched to the Ingersoll-Rands."

"Tubing is run to the top of the sand, but the wells are flown through the casing. It is planned to change to the tubing as the output declines. A Regan oil saver is used as a part of the Tidal hook-up."

"Average daily production on Tidal Oil Company's University F lease, Church and Fields pool, Crane County, Tex., for 29 days on air:

Well number	Production, barrels
2	1,110
3	1,144
4	1,482
5	1,520
6	1,112
1	1,423

"Variation in the output can be seen from the following facts. The first day on air, No. 2 made 1,118 bbl. On July 20, the output from this well was 1,153 bbl. Well No. 3 started off at 1,238 bbl., but gradually declined until the yield was 843 bbl. when air was taken off, July 20, on account of proration in the amount of oil bought by the purchasing company. Well No. 4 started at 1,657 bbl., but had dropped to 1,200 bbl. when proration went into effect. Other declines were about as shown in the wells listed. Paraffin trouble was undoubtedly responsible for some of the slump in these wells, inasmuch as Tidal is flowing through casing."

"Well No. 4 is a good example of the possible recovery by allowing the wells to flow: Maximum production of this well flowing by heads was 908 bbl., against 1,200 bbl. on air, giving nearly 300 bbl. gain through the use of air."

A detailed drawing of an air-gas-lift compressor plant layout appeared in the *Oil and Gas Journal*, the description having been prepared by J. L. Dwyer:[1]

"The reference drawing will afford the man far from the field an adequate idea of the position of all the mechanical apparatus, and it may give to some engineers a thought towards pipe economy, for this particular plant layout was designed with a thought toward economy of pipe. In spite of all the air-lift plants which have been constructed in recent months, there is still a sharp division of opinion as to the most practical and most advantageous layout for the equipment. The type plant shown in the drawing has been constructed on several leases in the Seminole field, which has been the scene of the world's greatest air-lift activity."

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[1] Dwyer, J. L., Mechanical Apparatus for Air-gas Lift, *Oil and Gas Jour.*, p. 83, Oct. 20, 1927.

"Starting with the gas engine, which is the source of power for most of the plants in the Seminole area, the plant illustrated shows four 90 hp. gas engines driving four gas compressors. The engines are shown at the bottom, and the compressors are above them on the drawing. The four-unit plant shown is a size which may be used for the average lease. The engines are water cooled, and the cooling water comes from a combination tower and tank which is placed sufficiently high above the engines to permit the cooling water to flow by gravity to the engines, eliminating any need for pumps on this operation. The water lines are shown in the headers at the end of the plant. The headers are shown leading into the engine and compressor which comprise the unit at the right of the drawing."

"The compressors are equipped with similar water intake lines, and outlet lines but of a smaller size. The water intake and outlet lines on the engines are of 8-in. pipe, while the lines on the compressors are 6-in. size. The water circulation necessary for this system is provided by the gravity flow of water into the engine and compressor cylinder jackets, and from the cylinder jackets it again gravitates into the water outlet headers which run parallel to the sides of the plant building."

"The water after passing through the cylinder jackets passes into the outlet lines, and is carried to the hot well shown on the drawing. The hot well is dug much lower than the plant flooring, and the water is gravitated into this well which is a large pit usually lined with concrete. From the hot well the circulation water is picked up by the centrifugal pump shown between the engine and compressor of the unit on the right. This centrifugal pump picks up the water and transports it to the cooling tower through which it drops down into the water tank. This is the only pump necessary for the water system of the entire plant. From the water inlet headers to the engine cylinder jackets the inlet pipes are 2-in. size, and the water outlet pipes are 3-in. size.

In considering this system it must be remembered that an adequate number of valves must be provided to permit the water being shut off from any individual engine or compressor without interfering with the movement of water to the other machines."

"The gas inlet and outlet headers for the plant are situated parallel to the water inlet and outlet headers. The fuel gas header for transmitting the gas to the engines is placed on the side of the plant nearest to the intake apparatus and distributed through this line. On the compressor side of the plant, the gas to be used in the flowing process is taken in and run through an intake scrubber which removes any impurities and cleanses the gas in order to prevent the introduction of any foreign matter to the well and to the oil sand. From the intake scrubber the gas enters the gas intake header which runs along the compressor side of the plant. It leaves the header (which is generally a 10-in. size) through 6-in. headers and enters the compression chambers to be compressed to the required figure. After the gas is compressed, it leaves the compressor and runs through a pipe to the control house, which is situated adjacent to the main plant. At the control house the gas runs through an automatic control (if it be a mechanically controlled plant) and enters the lead line which runs directly to the well. The control house machinery is displayed in the drawing and only one line has been completed for convenience. For the four-unit size plant, four connections have been broken into the line but only one has been sketched completely. There are two lines for each unit, one for the intake gas and one for the outlet gas. Both gases are measured, and a permanent record kept of the volume of both. After leaving the control house the outlet gas enters the outlet scrubber which again purifies this gas and removes any foreign matter which may have been accumulated on its journey."

"The building which houses the air plant is generally of sheet steel over structural steel frames. As many of these structures are temporary, they are made of the lightest possible material which is easily transported should it be wished to dissemble the plant. The floor in the temporary plants is usually made of chat, although the larger plants which are intended as permanent installations have concrete floors, and are built with a view toward permanence. The plant referred to consists of a main building, a control house, and an auxiliary building. The dimensions of all buildings are given and the plant is rather a compact affair. The side elevation at the extreme left of the drawing shows the position of the engine, the compressor, and the driving belt and idler. The idler especially may not meet the approval of many constructors but it does away with the necessity of any wider-size plant and the Seminole plants of this type have given satisfaction."

"The auxiliary building houses the electric lighting equipment which furnishes the light for the plant and for the employees' houses, if they are closely located. It may also be used as a small tool house. The air tanks shown in the auxiliary building and also the main building are for starting the engines."

The following two figures show the air-lift compressor installation of T. B. Slick at Seminole.

A staff writer[1] gave the following notes on some troubles experienced with the compressors and also the tabulated safety precautions:

"High-stage compressor cylinders are a source of danger under certain conditions. The heat of compression in these cylinders is great at all times and if an explosive mixture should be drawn into the cylinder a serious accident might result. There are instances of such explosions on record. To avoid drawing in an explosive mixture engineers are causing all intake lines to be conducted outside of compressor buildings. In addition, it is good practice to have these intakes a considerable distance above the earth so that no gas accumulations hanging near the ground may be drawn in."

"Possibly the most frequent explosions at gas-lift plants in the Seminole districts have been in exhausts. The reason for these explosions is less clear than for some others. It is thought generally, that the explosive mixtures are caused by the lubricating oil. Temperatures are quite high at exhaust valves and it is thought that possibly excess oil from the cylinder comes in contact with a crackling heat or that the oil is at least vaporized. To avoid these explosions engineers are using high flashpoint oils and using the oil sparingly."

"One of the most frequent causes of high-pressure line explosions is said to be the result of improper changing from gas to air in the pressure system. When making a change operators

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[1] Safety Work Cuts Number of Accidents As Air Lift Makes New Hazards, *Nat. Petroleum News*, p. 26, Feb. 22, 1928.

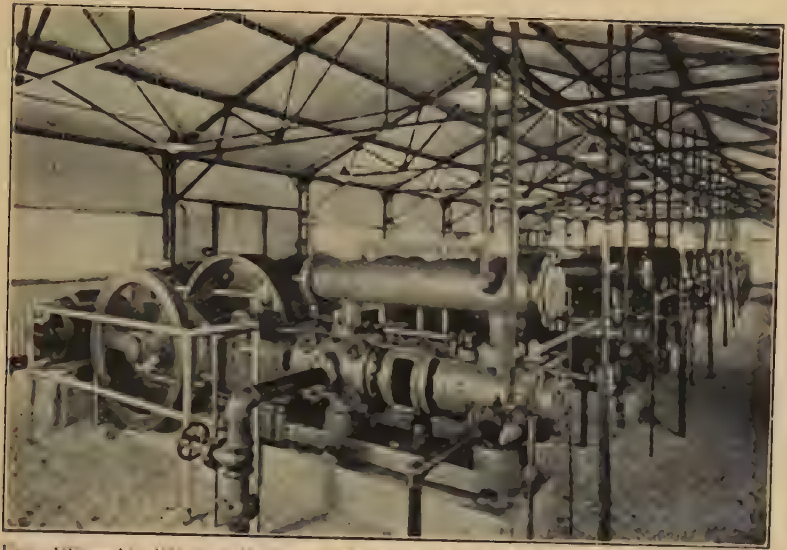

Fig. 128.—Air lift installation of T. B. Slick, at Seminole, Okla. (*Oil Field Engineering.*)

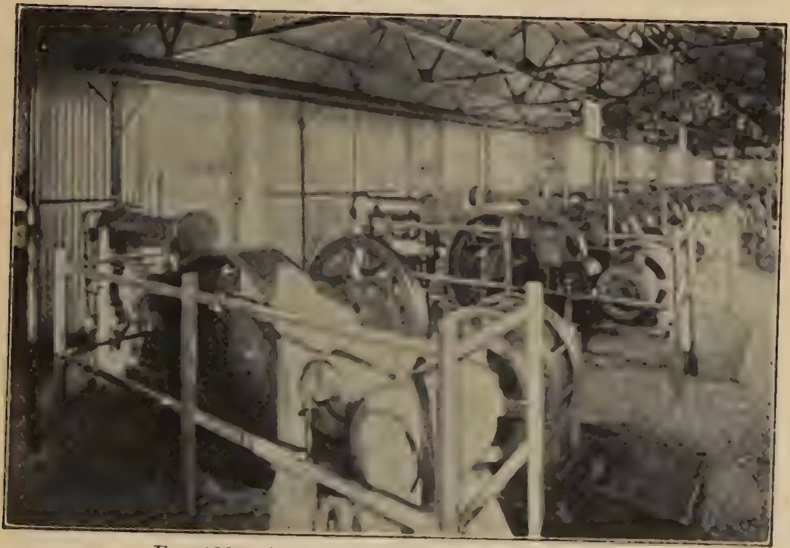

Fig. 129.—A compressor installation. (*Grizzle.*)

are supposed to allow compressors to run for about 20 min. to thoroughly purge the system before pressure is allowed to build up in the lines."

"There have been records of line explosions even when compressors have been run for 20 min. for purging. On gas lines drips are installed for the collection of gasoline which may condense out in the lines. If these drips are not drained before the lines are purged of gas or during the purging operation preparatory to switching over to air, an explosion may result when pressure is built up due to gasoline vapors from the drips being mixed with the compressed air. It is said that air containing from 1.5 to 6 per cent gasoline vapors is explosive and that gasoline has an explosive force eighty-four times as great as dynamite."

"The draining of gasoline drips before changing to air seems to be most difficult to impress on workmen. Probably this is because the drips are out in the field some distance from the compressor plants."

"1. Causes of explosions in compressors:

a. Excessive heating up of compressor from any cause.

b. Defective valves, leaks back from high to low stages causing air to churn in the compressor until it reaches the ignition temperature for the mixtures of air with oil vapors or gas present.

c. Improper lubrication.

(1) Low flashpoint oils are dangerous.

(2) Excessive amounts of oil are dangerous. Valves and cylinder walls should not be over wet with oil.

d. Improper cooling. Failure of cooling water circulation.

e. Carbonization of oil and ignition of carbon particles in presence of high-pressure air. Apt to occur in receivers and lines close to compressors.

f. Compression of dangerous mixtures caused by suction leaks outside of compressor or by dangerous mixtures in the return gases.

g. Charging containers with high-pressure gas before properly purging the containers to remove any gas or oil vapors that may be present or the reciprocal of this.

h. Danger from breaking high-pressure connections, copper tubing, small iron pipes, etc. Danger from whipping and swiping movement of broken pipe. Danger from ignition of gas and gas-air mixtures caused by brush discharge through broken connections. A slight tap on a high-pressure tube may cause the loss of a hand, a fire, or something more serious.

"2. Causes of explosions in pipe lines:

a. Placing exhaust lines and distribution lines close together in the same ditches at the compressor plants.

b. Accumulations of oxides and sulphides which are subject to spontaneous combustion in the lines.

c. Suction of air into return gas lines giving rise to explosive mixtures.

d. Friction and brush effects of loose particles impinging against walls of pipes, especially at short turns, elbows, etc.

e. Leaks through corrosion pits, breaks, etc., in lines, giving rise to excessive velocity of gas with suspended particles of rust or sulphides causing friction impact and brush effects.

f. Lightning striking a return gas line may ignite the air gas mixture in the line or may break the line, causing a fire and explosion by a brush discharge or by frictional and impact effects in the line.

"3. Safety precautions:

a. In general, try to eliminate conditions that are dangerous.

b. Avoid the possibility of sucking air and gas into the same compressor at the same time.

c. If one compressor is used for the compression of air at one time and gas at another time, be sure to purge the compressor at the beginning of each change.

d. Examine valves and cylinders of compressor frequently to ascertain the condition of lubrication. Remove excessive oil by wiping and washing with soap solution. Can use soap solution for lubrication for short intervals at a time to wash out excess of oil.

e. Install thermometers for watching the temperature of compressors.

f. Have positive water-circulating system and control the rate of water circulation at the outlet valve. Have inlet valve wide open so as to keep the cooling water system full at all times while compressor is running.

g. Don't use corrosive cooling water. Corrosion is said to be a common cause of compressor failures.

h. Use automatic controls to stop compressors when anything goes wrong with the cooling water system or the temperature of the compression system.

i. Make frequent analysis of return gases at repressuring plants.

j. Install explosion arrestors. Tubing, casing, or line pipe filled with iron turnings is not good because the iron rust or iron sulphide formed in such contraptions are sources of danger. Earle of the navy department recommends brass turnings instead of iron.

k. Use adequate popoff valve on discharge line from compressor.

l. Use safety discs or fusion plugs on lines, especially close to compression plant.

m. Install proper oil drip a short distance down stream from compressor.

n. Eliminate sharp angular turns in lines. Make long sweeping turns by curved pipe where possible.

o. Avoid projections in lines against which suspended particles in gas will impinge.

p. Introduction of slugs of air and gas, or slugs of exhaust gas into the distribution lines by introducing these gases intermittently at the compression plant."

It is quite natural that any development, such as an air-gas lift installation employing the pressures that it does and handling, at times, mixtures of air and gas which may easily be within the explosive mixture proportion, should present some hazards.

In order to lessen these hazards, the Bureau of Mines has suggested the above code of safety precautions.

Distribution Systems.—There were three systems or hook-ups of distributing the compressed agent developed, each of which has its advantages and advocates. The individual well installation consists of the required number and size of compressors being set and operating on one well alone. The central plant installation consists of having all the compressors located in one or more groups and the compressed agent being distributed from these central plants through either the so-called "loop system" or the "header system."

Brundred[1] describes the loop and header distribution systems as follows:

"*Loop System* (Fig. 130).—It must be noted that this calls for a complete closed system whereby the gas is distributed directly from the compressor station to a main input gas system serving all of the wells."

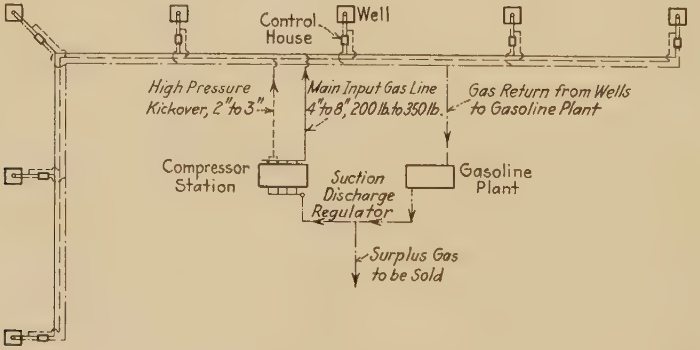
Control House
Well
High Pressure Kickover, 2" to 3"
Main Input Gas Line 4" to 8", 200 lb. to 350 lb.
Gas Return from Wells to Gasoline Plant
Compressor Station
Suction
Discharge
Regulator
Gasoline Plant
Surplus Gas to be Sold

FIG. 130.—General layout of typical gas lift plant. Loop system. (*Brundred.*)

"The print as shown calls for one or two high-pressure units installed in the compressor station to serve a high-pressure kick-over line when it becomes necessary to get a well started. When not used for kick over such units are used as a part of the main compressor stations serving all of the wells. In small stations but one kick-over unit would be required."

"Another plan is to have all of the compressor station units designed for a standard discharge pressure equivalent to the main-line pressure and not made for high-pressure work. Thus volume is obtained, rather than pressure. In such a system one or more high-pressure booster compressors are connected up near the compressor station in order to furnish the high-pressure gas necessary to get the well started. Such compressors take their intake from the main gas-distributing system."

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[1] BRUNDRED, L. L., Practical Production of Oil by Gas Lift, *Oil Weekly*, Nov. 11, 18, 25, 1927.

"It will be noted from the print that the wet gas is returned through the 'gas return line,' through the gasoline plant, and finally reaches the intake header at the station. In all cases a blowoff between the gasoline plant and compressor station must be provided, as the natural wet gas coming from the sand augments the gas used in flowing so that the system is not only kept full but is overcharged."

"*Header Control System* (Fig. 131).—It will be noted that this system calls for all of the compressors to discharge into a common header where the gas is then distributed directly to the wells through individual lines. The volume controllers are installed on these lines in the header house and furnish a record of the volume of gas required by each well."

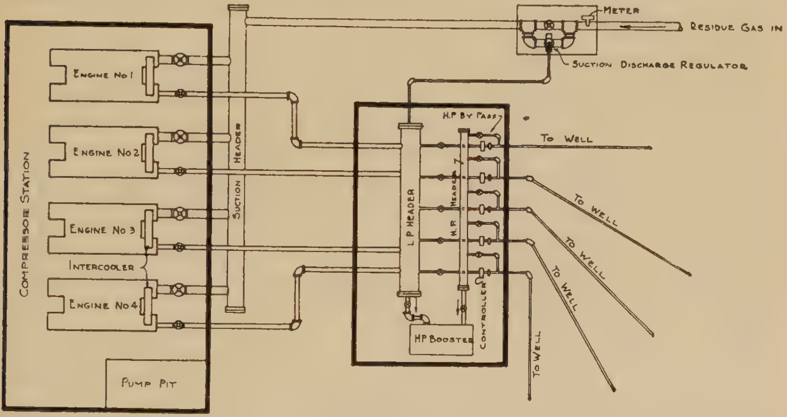
Meter
Residue Gas In
Suction Discharge Regulator
Engine No 1
Engine No 2
Engine No 3
Intercooler
Engine No 4
Compressor Station
Pump Pit
Header
Suction
H.P By Pass
To Well
L P Header
H.P. Header
Controller
HP Booster
To Well
To Well
To Well
To Well

FIG. 131.—General layout of typical gas lift plant. Header control system. (*Brundred.*)

"Attention is called to the small header marked H. P. header located behind and above the main header. It will also be noted that there is a small auxiliary unit at the right of the building. This unit is used as a booster to pick the gas up at the main header and raise the pressure to whatever kick-over pressure is necessary, discharging directly through the high-pressure header to the well to be kicked over. In this way the gas by-passes the controller during the kick-over operation. When this is accomplished the booster unit is shut down and the gas passed directly through the main header."

"The main advantage in the loop over the header control system lies in the fact that all of the recording instruments are directly at the derrick floor and, therefore, reflect immediatley any changes taking place. The main advantage of the header control over the loop system lies in the closer supervision and closer manual control of the volume of gas for each well in the event of accidents to the plant and interruption of service. The shape, size, and general layout of the property will control to a great extent the system to be selected."

The types and makeup of headers, as such, well be covered in a succeeding section.

The subject of distributing systems was discussed by Swarts,[1] as follows, in his paper which was presented at the Fort Worth meeting of the Petroleum Division:

"Two general plans of air and gas distribution were used, one employing the header system in conjunction with a central plant supplying a large number of wells. The other system consisted of a battery of compressors directly connected to an individual well. The header system was more commonly used. Many variations in the header system were evident but all accomplished about the same results. The manufacture of gasoline in connection with lift work resulted in special designs of plants. The majority of plants provided for a working header and a high-pressure header for starting wells. Starting headers were divided into as many as four sections, so that each section could be used simultaneously in starting a well, thus allowing four wells to be started at once. Several plants contained intermediate headers between high and low compressoin which with fuel and water headers made as high as seven headers per plant."

"The flow of gas in a plant using the header system is as follows: The gas enters the system through two scrubber tanks, thence to a 15½-in. intake header to the low compression cylinders, compressed to 50 or 55 lb. and discharged into a 10-in. low-pressure discharge header. From the low-pressure discharge header the gas passed through condensing coils to an 18-in. by 7 ft. low-pressure gasoline accumulator. Gasoline was removed by an automatic gasoline trap. From the low-pressure accumulator the gases passed to a 12-in. high intake header, thence to the high-compression cylinders and was compressed to about 250 lb., passing direct through the cooling towers to the high-pressure gasoline accumulators. From the high-pressure gasoline accumulators the gas passed to a working header and was distributed to individual wells through volume control devices and orifice meters. From the high-pressure gasoline accumulators the gas could be directed to a high-pressure starting header capable of handling four wells at one time."

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[1] Swarts, C. R., Mechanical Installation for Gas-air Lift in the Seminole Area, *Petroleum Development and Technology*, p. 78, 1927.

"Where headers were not used, the distribution of gas through the plants was very similar. The gas passed through scrubber tanks to a 20-in. low intake header, thence to the low compression cylinders and compressed to 50 or 55 lb. After low compression, the gas passed directly through the condensing towers to the low-pressure gasoline accumulator, thence to the high compression cylinders and after compression passed to a high-pressure gasoline accumulator, thence to a regular pipe-line manifold. This permitted the distribution of gas from any compressor to any well. No volume control devices were used on this type of plant, the volume being regulated by pinching the intake valves on the compressor or pinching the valve controlling the flow to wells. Orifice meters at the plant or well measured the flow of gas. Water circulation was either forced feed or gravity flow and was so connected as to permit flow from the cooling tower or from the condensing tower as in the plant using the header system."

"Many variations were evident in both types of plants. In many plants no cooling of gas and the extraction of gasoline was attempted after high compression, the gas going directly to the wells. Nearly every plant allowed for the extraction of some gasoline between low and high compression. The coolers used to extract gasoline were either the shell type placed vertically or horizontally or coils sprayed by water."

"In each of the two general types of distribution there are advantages and disadvantages relating to the use of gas and air and the utilization of power. Under the header system, compressor capacity can be fully utilized as only the number of compressors necessary to flow the wells need be used. The breakdown of a compressor does not shut down a well as other compressors can take on the load of the broken compressor.

Pressure carried on the header must necessarily be greater than the largest pressure required to flow a well. Any defect in the header would cause the shutdown of the entire plant. The change from air to gas cannot be made without shutting down the entire plant."

"Under the system in which the wells are directly connected to a battery of compressors, change from air to gas can be made one well at a time without shutting down the entire plant. Shutdown of a battery of compressors means the shutting down of a well. The maximum capacity of a battery of compressors is not fully utilized when low working pressures are required."

Another writer states as follows in regard to the distribution of the compressed agent:

"Requirement at the well as to volume and pressure controls the size of distribution lines. The practice of allotting one large compressor, of, say, 850 cu. ft. displacement per minute, arbitrarily fixes the amount of air delivered to each well. It is obvious that, where lines are placed in a well to such submergence depth, that the pressure limit of compressor at speed is reached, the quantity of air supplied is constant as to volume measured at atmospheric pressure, and also at operating pressure. No group of wells has such a fixed ratio; some wells require more air and more pressure than others, and these should be adjusted to the well."

"For instance, with a well operating in a low rock-pressure area of the field, the air line would be set deeper, to obtain a constant operating pressure, but, being set deeper, setting up a greater lift in feet, the quantity of air required is greater than where rock pressure is higher, and the air line is not set as deep. Lowering the air line at intervals as the rock pressure and consequent static pressure lowers sets up different requirements as to air and pressure."

"In some installations a set of distribution lines, one line per compressor per well, was used. It would be preferable to increase the duty of compressor plant or, in other words, to lower the cost of compressor plant per well, to install trunk lines—a starting line built for pressures as high as needed—not over 1,500 lb., and an operating line for distribution of gas to wells started. Taking, for instance, an 160-acre lease, these lines would begin at the plant and surround the lease lines with a loop or an endless line, valved so that the supply of air or gas has duplicate lines to each well."

"At the well, the supply of gas or air to each well is controlled by throttling through orifices, to the exact pressure and quantity desired. It will be found that the same delivery of oil from a well can be secured with a minimum of plant capacity and that surplus from all compressors is available for additional wells, operating the compressors in battery instead of singly."

"Making exact calculations of an installation of this kind, and comparing it with an installation where each well has its individual line and compressor, the net result is that the horsepower and size of compressor plant may be reduced 30 per cent, which, in terms of cost of compressor plant, is about $3,000 per well."

"In addition, the cost of distribution lines is lower with compressors in battery, for equal capacity of small pipes, say 2-in., is secured at much less expense with a single larger pipe, for one 6-in. pipe has an equal carrying capacity of twenty 2-in. pipes, with no greater line loss of pressure."

"At the junction of line to well with trunk line, there would be installed an orifice meter for measuring gas taken from any line used for operating."

Pennington[1] makes the following statement:

"The method of hooking up differs with fields, and with operators of the same field. That the practice of hooking from one to five compressors to a single well employs more compressor capacity than necessary is immediately seen when we know that the air requirement as to quantity varies with each well, especially when tubing is lowered from time to time."

"Air or gas may be pumped down the tubing, and the well flowed through the casing, or air or gas may be pumped down the casing and the well flowed through the tubing, or a double line may be run, with air down either the inner or outer lines and the oil up either the inner or outer lines. But which method affords the most economy?"

"In a deep well, operating at, say, 200 lb. pressure at the plant, with, perhaps, 150 lb. at the bottom of the well, air or gas, at the bottom is reduced in a volume as the number of atmospheres, which in this case is approximately 16, and 1 cu. ft. of air then, at the bottom of the well, expanding gradually as it travels upward, has a steadily increasing velocity, together with the oil. With an entrance velocity of 10 ft. per second, neglecting slippage for the time, the velocity at the surface is apt to be near sixteen times that at the bottom. With 50 per cent slippage, the velocity at the surface is 80 ft. per second, which in hydraulics is an extremely high velocity, and which, in air work in wells, is entirely unnecessary, and too high for efficient work."

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[1] PENNINGTON, HARRY, Lift Efficiency Depends upon Skill in Design and Operation, *Oil Weekly*, p. 82, Aug. 19, 1927.

"But unless the inlet velocity is held to, say, 7 ft. per second, and an average struck, of, say, 25 ft. per second, there is no means of reducing outlet velocity except by employing a tapered flow line, which is seldom done."

"Then, these high velocities do prevail in the field, and with them, if the air and oil mixture strikes a coupling every 20 ft., when flowing up around an air line, turbulence is set up, with high friction loss. But, flowing up a smooth interior flow line, this objection is removed, which resolves this question into one of flowing only through a line without any obstructions, or a central flow line."

"This eliminates sending air down a central line, and flowing up the casing, for, in addition to the foregoing objection, it will be found in almost all cases that the uptake area of casing less the area of the air line is far greater than necessary for securing a reasonable velocity."

"Sending air down the casing and up the central flow line is the next-best bet, but, sending air down a line inside of casing, and flowing oil up through a small line inside of the air line, is the best practice, as shown by many tests. But, where an improper uptake area per unit volume of oil-air mixture is used, there is no hook-up that will prove best. Correct proportions are assumed in this argument."

One practical point of operation should be kept in mind, and that is that the gas packed in the system is sometimes sufficient to care for surges when starting wells or changing working conditions. The surplus gas stored in the system permits operation from a central plant without upsetting the equilibrium of the system. It is more economical to build a central plant than to construct individual compressors at each well from the standpoint of both equipment and labor. It is, however, very desirable to have two or three portable compressors mounted on wheels which may be connected up to wells to find out their characteristics before the installation of a large plant on a lease. By testing each well for a sufficient period, the total plant requirements may be ascertained and the correct size of compressors determined.

Control.—The ideas and some details of the objects and systems of controlling the input agents to air-lift installation were given under the subject of Controlling (Chap. XV).

Extracts and illustrations from Brundred's[1] articles are given here:

"The hook-up shown by Figure 132 is used primarily in conjunction with the loop system of distribution. Certain modifications would be necessary to adapt it to the header control system. Attention is called to that part of the figure showing a small rectangular house, preferably 6 by 8 ft., located approximately 20 ft. from the edge of the derrick floor. In this house all of the operating instruments are installed as follows:

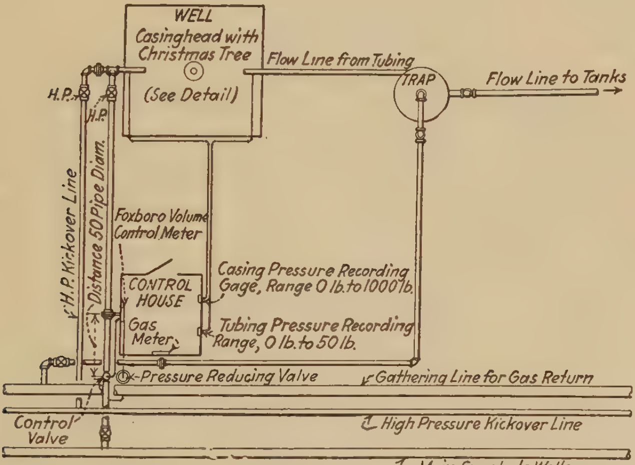
WELL
Casinghead with Christmas Tree
(See Detail)
Flow Line from Tubing
TRAP
Flow Line to Tanks
H.P.
H.P.
H.P. Kickover Line
Distance 50 Pipe Diam.
Foxboro Volume Control Meter
CONTROL HOUSE
Gas Meter
Casing Pressure Recording Gage, Range 0 lb. to 1000 lb.
Tubing Pressure Recording Range, 0 lb. to 50 lb.
Pressure Reducing Valve
Gathering Line for Gas Return
Control Valve
℄ High Pressure Kickover Line
℄ Main Supply to Wells

FIG. 132.—Diagrammatic layout of control house and controls. (*Brundred.*)

"*Volume Controller.*—In operation, gas from the high-pressure kick-over line is turned into the well to get it started. Later, after the first high static column is removed, the valve on the main supply line is opened and the one on the kick-over line is closed. The gas used in flowing is thus turned through the volume controller. It will be noted that the volume controller records not only the volume going through the instrument but maintains this volume automatically for any given setting of the instrument regardless of the variations in the pressure on the main supply line, provided, however, that such variations are not too extreme."

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[1] BRUNDRED, L. L., Practical Production of Oil by Gas Lift, *Oil Weekly*, Nov. 11, 18, 25, 1927.

"*Casing Recording Pressure Gage.*—As previously stated, once the well has been kicked over, it is essential that it be allowed to settle down to a constant flow with no variations in pressure shown on the input recording meter. This instrument records varying pressures in the form of waves; it immediately indicates when the well is 'heading' and that either not enough gas or too much gas is being put through the controller. It then becomes necessary to make certain simple adjustments in the controller in order to raise the differential and permit more or less gas to pass through it. Within a short time it will be noted that the 'heads' are more frequent but of less intensity. The wide fluctuations on the chart then will have ceased and the waves will have begun to approach a smooth circle, indicating that the setting of the controller is almost correct. Further control of the volume will completely settle the well down to a steady flow, with no variations in pressure. Then, and then only will the recording gage show a perfect circle and thus represent the best efficiency for that setting of tubing and for the particular conditions found in the well."

"*Tubing Recording Pressure Gage.*—Attention is also called to a second recording pressure gage shown in the control house. This is attached to the output or flow line. Variations in the pressure recorded here show that the volume circulated into the well is not proportionate to the volume of fluid being lifted. When this chart and the input chart both show practically no variations in pressure, the indications are that maximum efficiency is being obtained for the particular set of conditions in the well."

"It is a known fact that any well which is flowing by heads, whether it be flowing naturally or artificially with the gas lift, is inefficient and has either too little or too much gas. It is very seldom found, however, that such flow is the result of too much gas; it is practically an axiom that any well flowing by heads has too little gas. Numerous cases are available where a change of 20,000 cu. ft. per day from the correct volume introduced into a small well has caused a loss of as much as 15 per cent in the production."

"*Output Gas Meter.*—Another instrument located in the control house meters the total gas coming from the well. This is merely a standard orifice meter. The volume controller meters the input and the gas meter meters the output gas. From a computation of the two meter readings, the circulated and net gasoil-ratios can be computed."

"When using the header system of distribution, the so-called 'hand control' or 'automatic control' may be used, all installations of control apparatus being made at the headers. A diagram of the hook-up for an automatic installation is shown in Fig. 133."

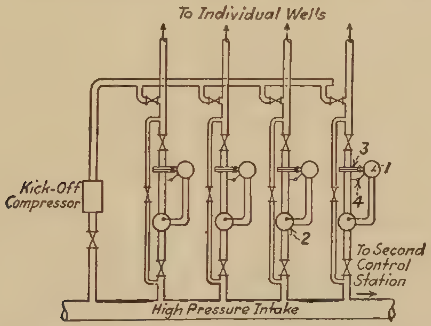

Fig. 133.—Diagrammatic layout for controlling servicing of gas to wells from central automatic control points. (*Bennett and Sclater.*)

1. Differential and static recording pressure gage with differentially operated pilot valve.
2. Diaphragm volume control valve operated by high pressure gas through pilot valve.
3. Orifice plate.
4. High pressure gas to pilot control valve.

As described by one writer:

"In operating the first installations, no attempt was made to regulate the gas volume introduced to the wells, other than by the number of compressors used. As the compressors were set at the well, no complicated manifold was necessary; the discharge of the compressors was connected direct to the well. When the compressors were installed in a central station, it was found advisable to use a manifold of some description. Several different designs were suggested and tried, but all had the same object in view, namely, to make it possible to switch any compressor, or any number of compressors, onto any well connected to that particular station. This was usually accomplished by connecting the discharge line of each compressor into all the lines to the wells with suitable gate valves. Individual lines were laid from each well to the compressor station. This system, while it did not permit close regulation of gas volume, was used quite extensively on account of the simplicity of operation."

It is now recognized that constant volume is of great importance in gas-lift work. An irregular supply of gas will make the wells head, sometimes violently enough to break out the trap connections; it also has a detrimental effect on the production. A volume too large is liable to produce excessive emulsification besides causing a large gas-oil ratio with its attending waste of energy. The use of volume controls has also made possible the use of a high-pressure loop line connected to all the wells and the volumes regulated by some type of flow controller. This effects quite a saving in line pipe. The majority of operators, however, seem to think that this saving is offset by controls being widely scattered, so the general practice is to install the volume controllers at the compressor stations.

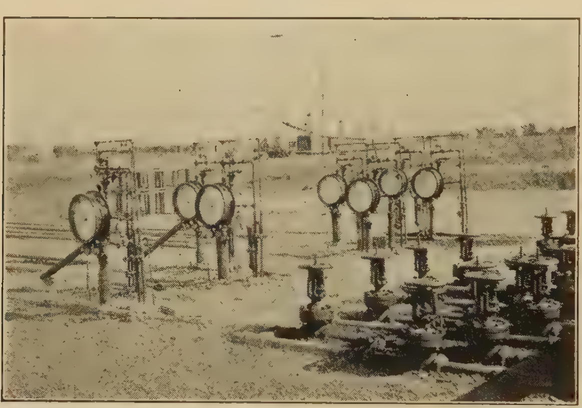

FIG. 134.—A central input gas meter station.

Volume regulation is accomplished by the use of one or more of several devices, commercial flow controllers, needle valves, orifices, etc. There are several types of flow controllers on the market, all of which operate on the same general principle. The main valve is operated by a diaphragm which is connected to the upstream and downstream side of either an orifice or butterfly valve. Any change in differential across the orifice or butterfly valve will affect the diaphragm and open or close the main valve. When using these controls, common practice is to install a main header into which all the compressors discharge. The individual lines to the wells are then connected into the header and the volume controls so installed that the controller and header may be cut out and one particular compressor, or, in some stations, any available compressor, used to build up the high pressure usually necessary to start the well. As a rule, an orifice meter is either incorporated in the controller or installed in conjunction with it. While the cost of this equipment is not excessive, it is sufficiently high to prevent its universal use and some operators have developed very satisfactory systems of volume control by the use of needle valves or orifices. The connections used are much the same. All the compressors discharge into a common header at a pressure slightly higher than the highest operating pressure of the wells. This pressure is held within a few pounds and the orifice, or needle valve, in the lines to the wells can be regulated to give the correct volume constantly. As before, a by-pass is used for starting the wells.

Figure 134 shows the central meter station of one installation in the Bowlegs field. Foxboro volume controls are installed.

Header Installations.—Practically every company that used distribution headers in their air-gas lift work designed and built their own layout. Some are simple, while other types are rather elaborate; and though the high-pressure fittings which are necessary for even the simplest installations cost a respectable sum, one often wonders at the amounts tied up in the more complicated installations.

The easiest and surest way to secure the absolute flexibility of operation is to have each supply line, from whatever the source, be it one or a dozen compressors plus some starting machines, connected to each discharge line by an individual valve. This practice leads to the construction of some complicated and costly installations and may have been justified, due to the lack of time for designing economical header systems, during the initial periods of the application to practice of the air-gas lift. On the other hand, some of the header installations show, in their characteristics of simplicity and real flexibility, the attention and thought which was given the matter.

It would be well, at this time, to point out the importance of using connections sufficiently strong to withstand the high starting pressure generally encountered. The majority of accidents that have occurred can be traced back to the failure of connections such as ells, tees, or gate valves, and investigation has often disclosed the fact that standard connections were being subjected to several times their working pressure. The cost of connections designed for a working pressure suitable for any installation is negligible compared to loss of property and life that may be caused by the use of light connections.

The discharge lines should be manifolded outside the building in such a way that compressors can be conveniently switched from one well flowing line to another with as much speed as possible and either so arranged or labeled that operators can make no mistake in opening or closing the correct valves. The fact that some wells take a greater volume than others for efficient flowing and take different starting as well as operating pressures makes it desirable to arrange the manifold so that several compressors can be placed on any one line without interfering with the steady operation of the others. There are devices on the market for apportioning to individual wells the volume of gas found to be necessary for efficient operation, thus eliminating the necessity for separate lines from the central plant to each well. This system is used by some companies, but in its present stage of development it entails much closer supervision to assure satisfactory operation than where individual lines are used.

The following description was taken from an article by A. R. McTee:[1]

"In its air plant recently completed in Crane County, Tex., Church and Fields pool, the Eastland Oil Company has introduced a number of interesting new features."

"Chief among these are the special-design high-pressure manifold and the method of hooking up the wells. All air lines to wells are cross-connected so that any compressor or combination of compressors can furnish air to any well or combination of wells. This enables the operator to operate the various wells at a variety of working pressures without the necessity of all compressors carrying the maximum pressure of any single well."

"The volume of air to each well is automatically controlled by Foxboro automatic volume controls which are all installed in a single control house near the main plant. Each Foxboro instrument is by-passed so that replacement, repairs, or adjustment can be made without interfering with the well if it happens to be on air. Air is by-passed around the instrument which is down and the well is kept flowing."

[1] McTee, A. R., Interesting New Features in Eastland Air Plant, *Oil Weekly*, p. 31, Oct. 21, 1927.

"Considerable advantage is obtained by having all the control apparatus in one place. One operator can handle all eight wells on the lease, and a glance at the controls at any time will give him the condition at every well."

"The instruments are all set on concrete bases with ample room for workmen to get around the controls whenever necessary."

"On both low- and high-pressure air lines there are scrubber tanks which clean the air to get rid of moisture from condensation, lubricating oil from the compressors, and dirt. One set of tanks receives the heated air as it comes from the compressor. Then, when the air is cooled in the condensing coils and is put through the high-pressure side of the machine, it goes into the second scrubber before finally getting into the main air line."

"The station consists of eight 80-hp., two-cycle Clark engines direct connected to two-stage compressors. Then there are three 125-hp. four-cycle Clark engines driving two-stage vertical compressors giving the station a total capacity of about 860,000 cu. ft. per day."

"This equipment is housed in a steel truss galvanized iron building, 36 by 140 ft."

George Reid of *The Oil Weekly*[1] staff published the following description of the Indian Territory Illuminating Company's installation in the Bowlegs field:

"Like many other operators in the Seminole fields the Indian Territory Illuminating Oil Company is erecting, and operating, compression plants for air- or gas-light work which will handle green or wet gas for recycling to the oil sands. This practice entails the actual construction of an old style compression type natural gasoline plant, for in the compression and cooling of the wet gas the gasoline is unadvertently extracted and condensed. In a sense these plants might be listed as gasoline plant installations, but since their primary purpose is for the recycling of natural gas to the sand for the purpose of artificially flowing the wells, they are essentially only gas-lift plants. Later, perhaps, as the field develops and conditions grow more settled, the gas-lift plants will enter the lists of gasoline installations, being installed for a dual purpose. Several of these plants are connected and hooked-up in such a manner that they may be speedily converted from the compression of natural gas to the handling of compressed air whenever such a change is necessary. The Bowlegs gas-lift plant of the I.T.I.O. Company is such an installation. Two-stage Clark compressors, six in number, were installed as the second unit of the installation. These are size 4 by 7½ by 20 in., 80 hp., 500-lb. rated maximum pressure. The machines are set on heavy concrete bases."

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[1] Reid, George, Application of Gas and Air Lifts at Seminole, *Oil Weekly*, p. 47, Mar. 25, 1927.

"This plant is designed and constructed in such a manner that the switch from air to gas or the reverse may be accomplished within a very short time. The air and gas lines both enter the compression plant to join just above the intake of the machines. All of the air lines are painted black, while the gas lines which connect into the intake lines of the machines are equipped with heavy-duty valves, and these valves are all painted bright red. When it is necessary to change from gas compression to air, all of the red valves are closed tightly and all of the black valves on the air lines, one to each machine, are opened. In the meantime, it is necessary to vent the lines of air or gas, whichever is present, to eliminate the explosion or fire hazard. Vent lines and valves are also provided."

"The original plant on this site and which is also in operation on the air lift at present consisted of four Chicago Pneumatic compressors, size 10 by 4½ by 10 in., which are belt driven by General Electric 75-hp. motors. Thus, at present the company has in operation on this site, ten compressor units. In addition to these already in operation there are three more Clark Brothers 80-hp. machines being installed."

"Accumulator tanks are installed for the collection of compression gasoline when the large plant is operating on wet gas. These tanks are welded throughout, provided with gage glasses in the usual manner and with blowoff lines for the removal of the gasoline to storage as it is condensed. Lines conduct the gas into the water sprayed cooling coils which are provided for the purpose of cooling the gas or air between the low stage, about 50 lb. pressure, and high stage, around 200 lb., and for cooling again after the high-stage compression."

"A general manifold is installed for the control of the gas in its direction of flow after the second cooling and at the point where it is diverted into whatever well or wells require it. This consists of ten separate manifolds and takes care of all of the compressors now in operation. Through this installation any portion of the compressed air from the machines may be directed

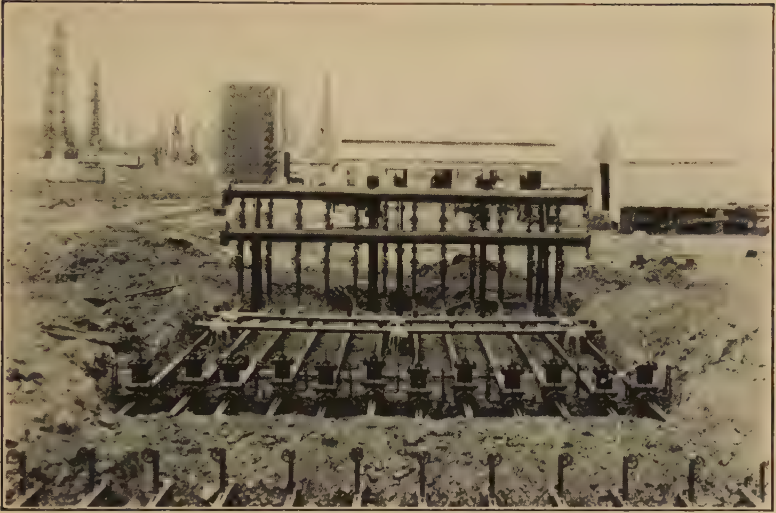

FIG. 135.—A Header installation. By use of these double-manifold headers, auxiliary compressors may be used to start wells on gas lift at high pressures without disturbing operation of main compressor units. This installation is on the O'Dea lease of the Barnsdall Oil Co. of California, Rosecrans field, where the company has nine wells on gas lift. (*National Petroleum News.*)

FIG. 136.—A typical compressor manifold and combination header installation.

to whatever point is necessary. If a certain well requires the output of two or three compressors, all that is necessary is the opening and closing of certain marked valves which causes the flow of air to be directed to the well desired. This practice lends flexibility and simplicity to the operation of the plant."

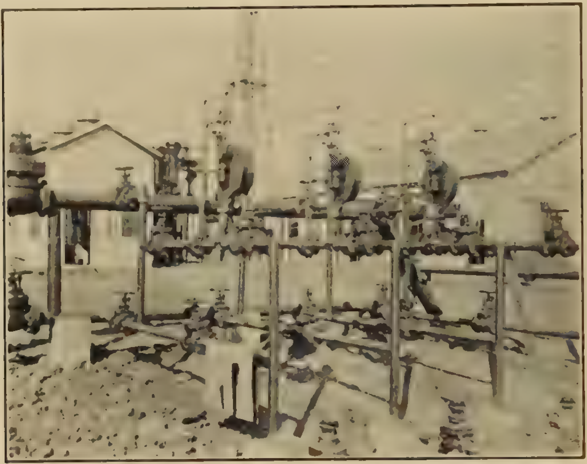

Fig. 137.—A typical installation of individual well lines and meters, from a common header.

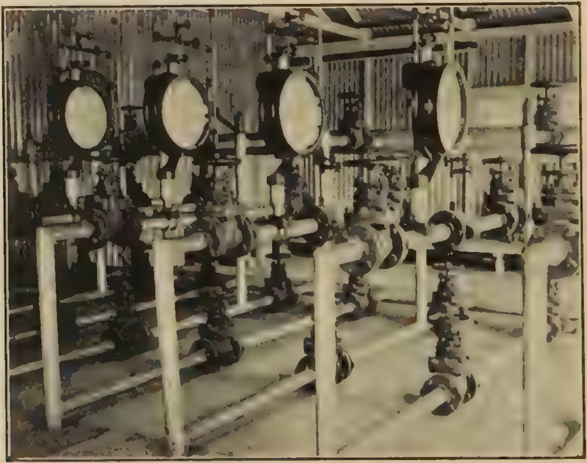

Fig. 138.—Individual well lines from flowing and kick off header. (*Note method of meter installation.*)

The following illustrations will give some idea as to the prevailing practices in regard to the types and installation of headers.

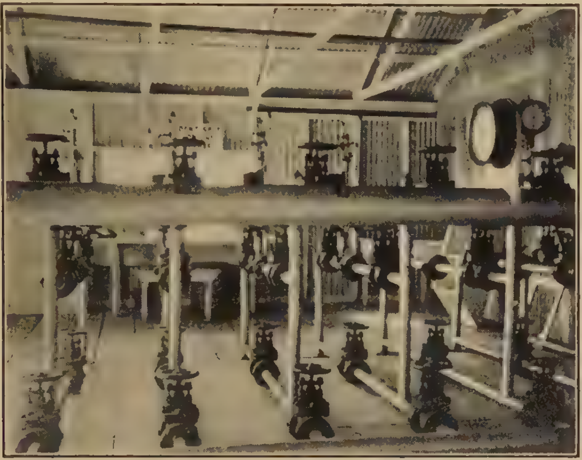

FIG. 139.—Individual well lines from flowing and kick off header.

Figure 136 shows the compressor manifold leading into the combination header system with the meter set-up system shown back of the header.

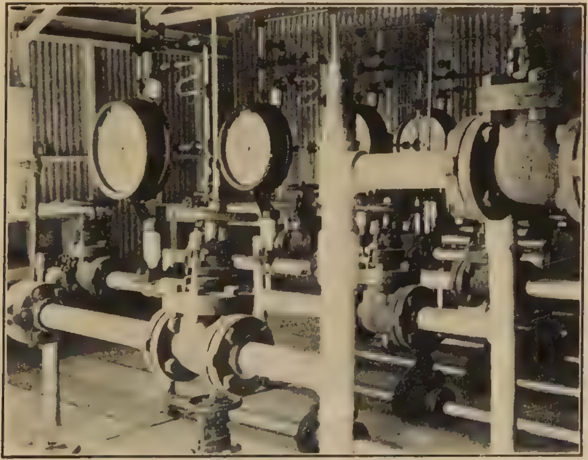

FIG. 140.—Control valves on individual well lines.

Figure 137 shows the central meter station and lines for each well with common header from the compression plant as installed on one lease of the Earlsboro field.

Figures 138, 139, and 140 show the interior of a central meter house, the individual meters and lines for each well taking off the large flowing header at the top and with the auxiliary high-pressure kick-off header at the bottom.

Well-head Connections.—The variety of well-head connections or Christmas trees seen in the fields and illustrated in the technical journals indicates the number of different ideas as to what may be considered necessary or useful toward operating a well on the lift. Various statements, discussions, and illustrations have been assembled here in order to advance many of the prevalent views and ideas on the well-head connections and to show what has been done along these lines.

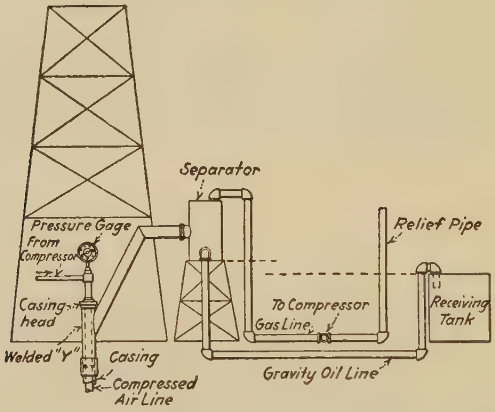

FIG. 141.—Discharge arrangement for air and gas-lift application. (*Shaw.*)

Shaw[1] discusses the subject as follows:

"The general method followed in equipping a well is shown in Fig. 141. In the early stages of production when the wells were large producers, the general arrangement at the top of the well that was found to be most serviceable is shown in Fig. 142."

"The practice was adopted of equipping each well with input and output meters. The general arrangement of pipe connections for the output meter is shown in Fig. 143."

"All of the wells equipped as above noted had the air-gas tubing lowered inside the casing, the oil being lifted through the annular space between the casing and the tubing. After the wells had declined in production from 400 to 100 bbl., a string of tapered tubing was inserted in the well and the oil flowed through the tubing in order to economize in the use of compressed gas."

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[1] SHAW, S. F., Air-lift Practice in the Seminole Field, *Petroleum Development and Technology*, p. 100, 1972.

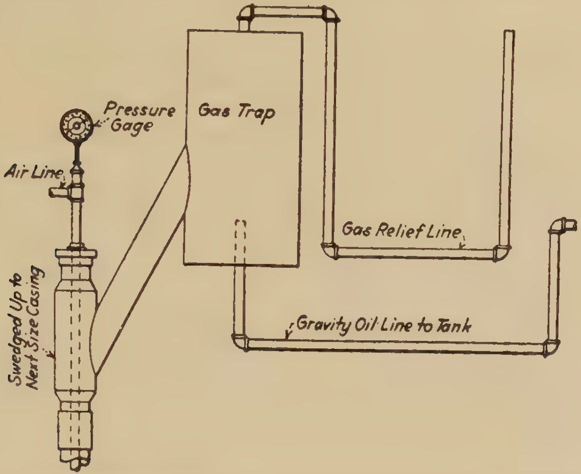
Pressure Gage
Gas Trap
Air Line
Gas Relief Line
Gravity Oil Line to Tank
Swedged Up to Next Size Casing

FIG. 142.—General arrangement at top of well when flowing between casing and tubing. (*Shaw.*)

"The arrangement at the top for starting wells with high pressures when using tapered tubing is shown in Fig. 144."

A comment which may be offered here is that the use of bull plugs, except those having wood inserts in the Christmas tree or in the flow line going to the trap, is very detrimental on account of the created turbulence and they should be avoided. For the same reason, the use of gate valves rather than globe valves is to be recommended.

The following illustration (Fig. 145) shows the well-head connections of one of the wells in the Seminole City field. This well was fitted with the tapered string of tubing.

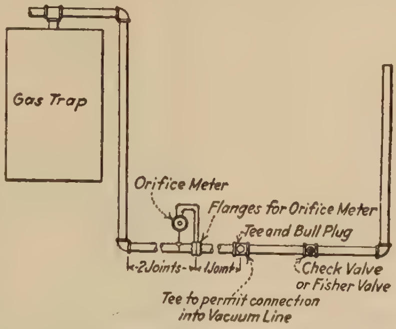
Gas Trap
Orifice Meter
Flanges for Orifice Meter
Tee and Bull Plug
2 Joints
1 Joint
Check Valve or Fisher Valve
Tee to permit connection into Vacuum Line

FIG. 143.—Piping connections for output orifice meter. (*Shaw.*)

It should be understood that the earliest arrangement of pipe connections was the outcome of a desire to make as few changes as possible from the time when the well was first brought in as a flowing well. These arrangements were all inefficient

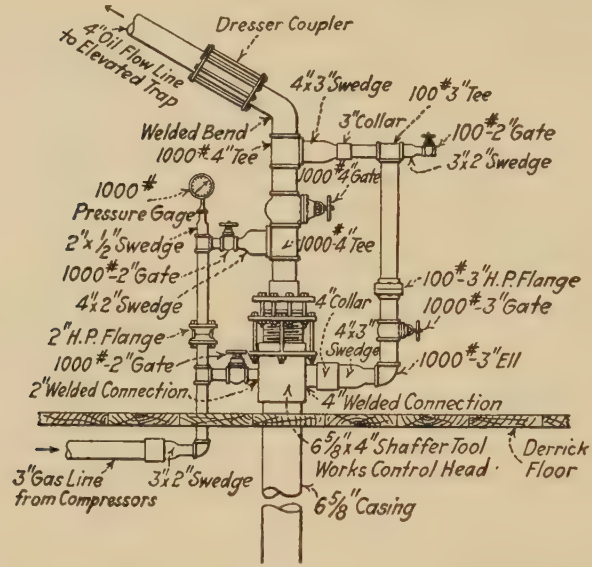
4" Oil Flow Line to Elevated Trap
Dresser Coupler
4"x3" Swedge
100# 3" Tee
Welded Bend
3" Collar
100#-2" Gate
1000# 4" Tee
3"x2" Swedge
1000# 4" Gate
1000# Pressure Gage
2"x 1/2" Swedge
1000#-4" Tee
1000#-2" Gate
100#-3" H.P. Flange
4"x2" Swedge
4" Collar
1000#-3" Gate
2" H.P. Flange
4"x3" Swedge
1000#-2" Gate
1000#-3" Ell
2" Welded Connection
4" Welded Connection
6 5/8"x4" Shaffer Tool Works Control Head
Derrick Floor
3" Gas Line from Compressors
3"x2" Swedge
6 5/8" Casing

Fig. 144.—Layout at top of well for flowing through the tubing. (*Shaw.*)

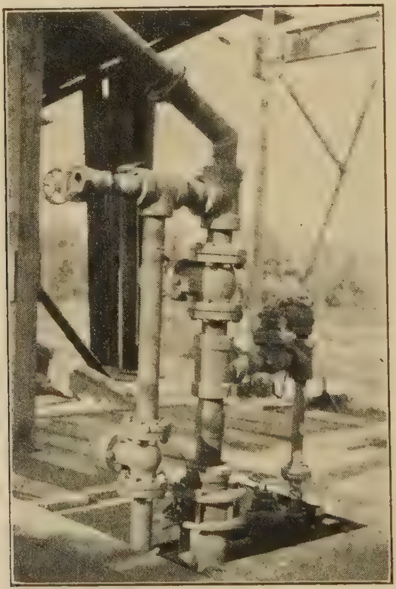

Fig. 145.—Typical well head connections of gas lift well.

so far as air-lift principles are concerned but were the outgrowth of conditions in the field where changes have met with little favor until lately, owing to the lack of knowledge of the principles that govern air-lift operations.

The following description was taken from Bond's[1] paper presented before the Petroleum Division of the A.I.M.M.E. at the Fort Worth meeting, 1927:

"The first wells produced by gas lift at Tonkawa were Wilcox sand wells that had ceased to flow and were being produced by swabbing. These wells produced into batteries of separators centrally located so that the flow lines ranged from 100 to 600 ft. in length. A string of 2-in. upset tubing was run into each of the wells and hung on the control head by means of a common tubing hanger. The gas was introduced into the wells through the tubing and the mixture of gas and oil flowed out of the well through the annular space between the casing and tubing. The production of the majority of the wells was increased considerably and the lifting cost was less than by swabbing."

"At that time no attention was paid to the length of flow lines or the elimination of right-angle bends. This has since proved to be of great importance. A good illustration of this is shown in the results obtained at Tonkawa in June, 1926, when the first changes were made. The separator at one of the wells was moved from approximately 100 ft. from the derrick to within 10 ft. of it. The control head was removed and replaced with a welded Y which was connected to the separator in a series of gradual bends. This flow line was the same size pipe as the well casing so there would be no restriction in flow. Figure 146 shows the hook-up as it appeared when completed. Immediately after these changes were made, the production increased 50 per cent. As there was no corresponding increase in the total gas volume from the well, a considerable decrease in the gas-oil ratio was also effected."

"Figure 147 shows the same general type of hook-up, except that it is used when flowing through the tubing. The gas is introduced into the annular space between the tubing and casing and the mixture of gas and oil flowed out through the tubing."

---

[1] BOND, R. I., Mechanical Equipment of Air-gas Lifts in Oklahoma and Kansas Exclusive of Seminole, *Petroleum Development and Technology*, p. 71, 1927.

“A combination hook-up for flowing through either the casing or tubing is shown in Fig. 148. The starting pressures, outside of Seminole area, are not high enough to require the general use of this type connection. In cases where high starting pressures are encountered and it is desirable to reduce this excessive pressure, the well is connected up as shown in the sketch and rocked. That is, the pressure is alternately built up and released, first

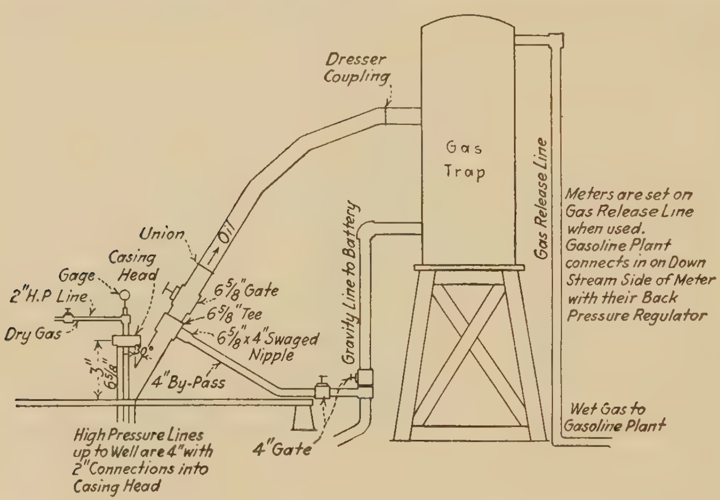
Dresser Coupling
Gas Trap
Gas Release Line
Meters are set on Gas Release Line when used. Gasoline Plant connects in on Down Stream Side of Meter with their Back Pressure Regulator
Union
Oil
Casing Head
Gage
2"H.P Line
Dry Gas
6⅝"Gate
6⅝"Tee
6⅝"x4"Swaged Nipple
30°
3"
6⅝
4"By-Pass
Gravity Line to Battery
High Pressure Lines up to Well are 4" with 2" Connections into Casing Head
4"Gate
Wet Gas to Gasoline Plant

Fig. 146.—Well connections for flowing through casing. (*Bond.*)

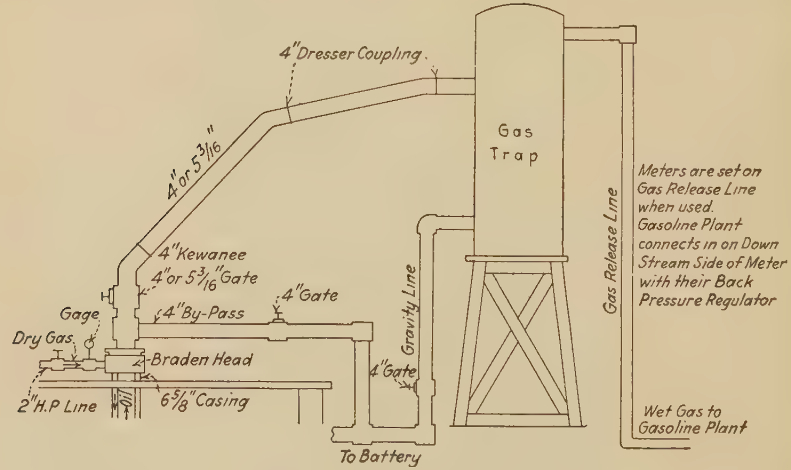
4"Dresser Coupling
Gas Trap
4"or 5$\frac{3}{16}$"
Meters are set on Gas Release Line when used. Gasoline Plant connects in on Down Stream Side of Meter with their Back Pressure Regulator
Gas Release Line
4"Kewanee
4"or 5$\frac{3}{16}$"Gate
4"Gate
4"By-Pass
Gage
Dry Gas
Braden Head
2"H.P Line
Oil
6⅝"Casing
Gravity Line
4"Gate
To Battery
Wet Gas to Gasoline Plant

Fig. 147.—Well connections for flowing through tubing. (*Bond.*)

in the casing and tubing, or *vice versa*, until the oil is livened up sufficiently to reduce materially the starting pressure."

"These figures do not show the position of the orifice meter. It is placed on the gas release line between the trap and the gas gathering line connection in order to measure all the gas from the well. Gas measurements of both the gas introduced to the well and the total gas coming from the well are worth many times the money spent for equipment in the way of meters, etc., to secure the information. No idea of the efficiency of the lift can be obtained without this information."

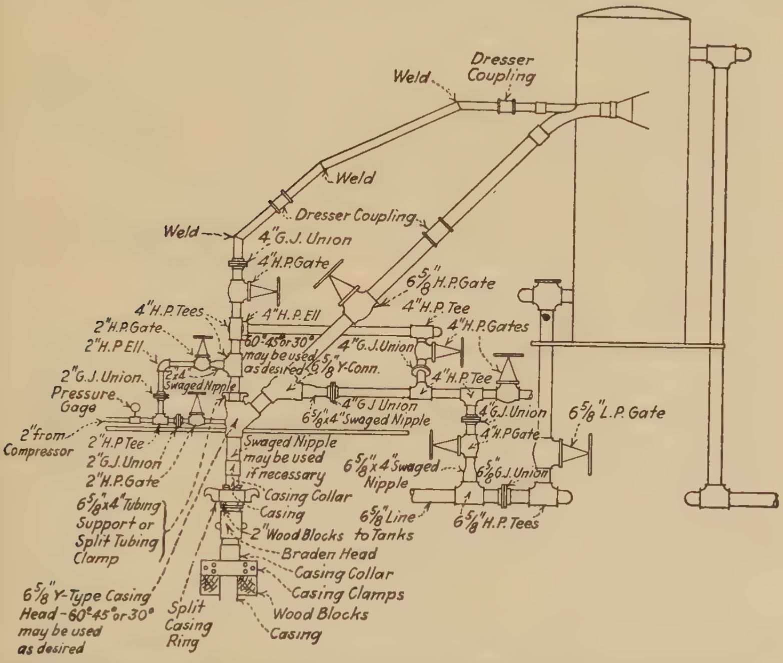
Dresser Coupling
Weld
Weld
Dresser Coupling
Weld
4" G.J. Union
4" H.P. Gate
6 5/8" H.P. Gate
4" H.P. Tees
4" H.P. Ell
4" H.P. Tee
2" H.P. Gate
2" H.P. Ell
60°-45° or 30° may be used as desired
4" G.J. Union
4" H.P. Gates
6 5/8" Y-Conn.
2" G.J. Union
2x4" Swaged Nipple
4" H.P. Tee
Pressure Gage
4" G J Union
6 5/8" x 4" Swaged Nipple
4" G.J. Union
6 5/8" L.P. Gate
4" H.P. Gate
2" from Compressor
2" H.P Tee
2" G.J. Union
2" H.P. Gate
Swaged Nipple may be used if necessary
6 5/8" x 4" Swaged Nipple
6 5/8" G.J. Union
6 5/8" x 4" Tubing Support or Split Tubing Clamp
Casing Collar
Casing
6 5/8" Line to Tanks
6 5/8" H.P. Tees
2" Wood Blocks
Braden Head
Casing Collar
Casing Clamps
6 5/8" Y-Type Casing Head - 60°-45° or 30° may be used as desired
Split Casing Ring
Wood Blocks
Casing

Fig. 148.—Combination connection for flowing through either casing or tubing. (*Bond.*)

Miller[1] states in regard to the California practice:

"Various types of packed casing heads are used in the casinghead or Christmas-tree assembly on gas-lift wells in California. The most important requirements of the casing head on a gas-lift well are that it be secured against leakage of gas and strong enough to support the string of tubing suspended in the well. Pressures of 900 to 1,000 and more pounds per square inch are required to start certain wells flowing, so that it is essential that casing heads be designed and packed to withstand such pressures. The weight that may come on casing heads varies with the size and length of the tubing and whether or not the tubing is suspended off bottom. Strings of 2½ and 3-in. tubing 4,000 to 5,000 ft. long are common in the California oil fields."

---

[1] Miller, H. C., Mechanical Installation for Gas-lift Pumping As Practiced in the California Oil Fields, *Petroleum Development and Technology*, p. 85, 1927.

"The gas connections are usually so arranged that the gas may be introduced through the tubing or between the tubing and the casing. This arrangement allows the well to be rocked as described under the heading Starting Pressures, until the fluid column in the eduction tube becomes sufficiently aerated to start the well flowing with normal working pressure. For convenience of starting, the valves in the gas line to the casing and in the by-pass line to the tubing are located close together on the derrick floor at the casing head."

"All gas-lift wells in California, however, are not fitted for rocking. Some operators rely entirely upon high gas pressure to start the flow of oil from the wells. This method of starting wells is successful where high-pressure gas from high-pressure or booster compressors is available and in wells where high starting pressures have no detrimental effect on the well. Since, however, the productive sands in many wells take gas at pressures less than that required to start the well flowing by introducing high-pressure gas, the only alternative starting methods used at such wells is rocking, lightening the column of fluid in the tubing by swabbing, and raising the tubing. To subject wells to pressure higher than the rock pressure even for a short time is dangerous practice. Sediment in the oil often clogs the pores in the walls of the well or the walls become plastered with mud. Such wells must usually be cleaned to restore the drainage area to its original condition."

Brundred[1] published his ideas on this subject as follows:

"Figure 149 shows in detail, the arrangement on the derrick floor. Although diagrammatic, it is designed to show an easily prepared and quickly operated Christmas tree to meet all of the conditions previously referred to. There are certain important features in this arrangement to which attention must be called."

---

[1] Brundred, L. L., Practical Production of Oil by Gas Lift, *Oil Weekly*, Nov. 11, 18, 25, 1927.

"1. It permits of turning the gas into the casing and tubing simultaneously.

"2. It permits releasing the high-pressure gas from either the tubing or casing directly into the slush pit. Were this gas suddenly turned into a separator, possibility of serious damage might result.

"3. The well can be flowed momentarily up through the casing as well as through the tubing, thus permitting of rocking to get the well started.

"4. The Christmas tree has but two unions of the box pattern to break, and, if suspended from a counterweighted line, when these two unions are broken, the whole Christmas tree can be swung back into the derrick without the necessity of handling by hand. Attention is called to the location of the two unions in that they are so placed as to permit the men to run tubing without interference.

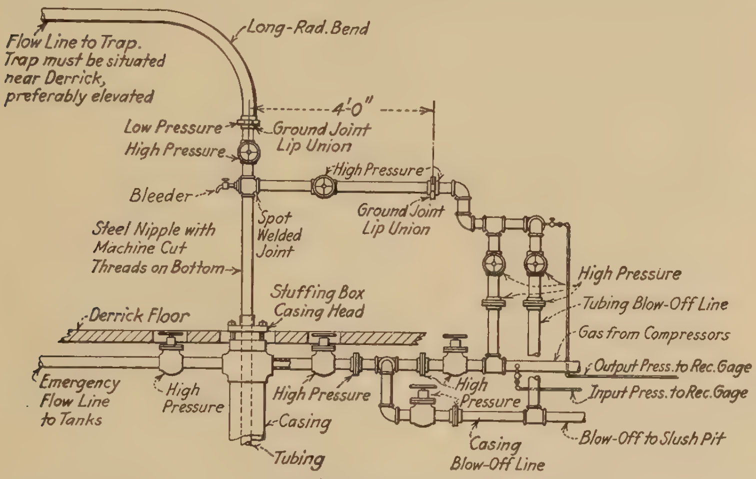
Long-Rad. Bend
Flow Line to Trap.
Trap must be situated
near Derrick,
preferably elevated
4'-0"
Low Pressure
Ground Joint
Lip Union
High Pressure
High Pressure
Bleeder
Spot
Welded
Joint
Ground Joint
Lip Union
Steel Nipple with
Machine Cut
Threads on Bottom
High Pressure
Tubing Blow-Off Line
Stuffing Box
Casing Head
Derrick Floor
Gas from Compressors
Output Press. to Rec. Gage
Input Press. to Rec. Gage
Emergency
Flow Line
to Tanks
High
Pressure
High Pressure
High
Pressure
Casing
Tubing
Casing
Blow-Off Line
Blow-Off to Slush Pit

FIG. 149.—Layout of typical gas lift Christmas tree manifold for large wells.
H.P. = High pressure
L.P. = Low pressure

"5. The wheels of all valves are flush with the derrick floor, rather than above it, where they would be constantly in the way and be a source of danger to the men running tubing.

"6. The small ¼-in. lines shown at the upper and lower right side of the figure are run to the control house for attachment to the recording pressure gages.

"The casing head as shown is of the split gland and seat type, designed to permit quick handling of the tubing."

At the present, with deeper drilling, it is not uncommon to find many wells where the fluid level stands up 2,000, 2,500, and even 3,000 ft. above the top of the sand. Were the tubing run directly to the top of the sand in a well of this kind, the pressure required to kick over this high fluid column would be so great that special machinery, capable of withstanding excessive pressure at the sacrifice of volume, would have to be used. In cases of this kind, therefore, this high static column is removed by successive stages in the following manner, as described by one writer:

"Often a fluid level finder is run to determine the height of the fluid column. The tubing is then submerged in the fluid about 1,000 ft., the well is kicked over and allowed to flow approximately 1 hr. from this level, thus partially removing the static head. The next step is to lower the tubing approximately 600 ft. further. In order to accomplish this, the gas must be cut off. The tubing then must be run quickly, otherwise the fluid coming in from the sand will again fill the well up to its previous high level. Speed, therefore, in getting the tubing in and getting the casing head repacked is of the utmost importance. The next step then, is to run the tubing approximately 400 ft. further, allowing it to flow for about an hour from this level. The next time it is lowered approximately 200 ft., and so on successively, by smaller and smaller increments the tubing is lowered until the bottom of it is placed at the desired level. Needless to say, the size of the increments depends solely on the rapidity with which the fluid enters the hole.

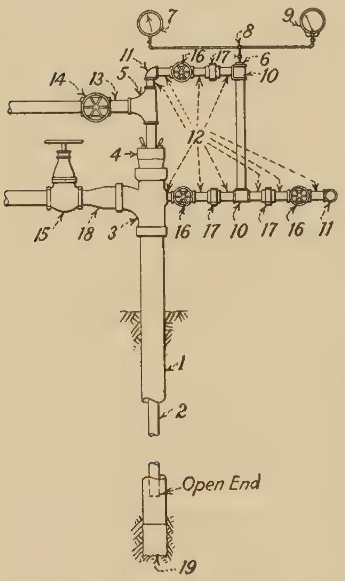

FIG. 150.—Typical well head connections for combination flowing. (*Porter.*)

"From the above, the necessity of having a quickly operated stuffing box, casing head, and Christmas tree is apparent. Where a well has been operated on the gas lift for some time and it has been deemed advisable to lower the tubing, say a 'fourble,' this should be accomplished, with the Christmas-tree layout as suggested, in a period of 5 min. or even less with a fairly experienced crew. With the average layout involving a large number of unions to break, excessive labor, and extra operations on account of a poorly designed head, it is not uncommon to find 20 to 40 min. consumed. The very purpose then of running the tubing in stages is thus defeated."

A. F. Hinton,[1] of the *National Petroleum News*, published a print of the well-head connection designed by H. P. Porter of the Gypsy Oil Company, which is shown here as Fig. 150.

A Christmas-tree arrangement based on the idea of the Marland's Panhandle installation[2] but without provision for running the wax cutter is shown in Fig. 151.

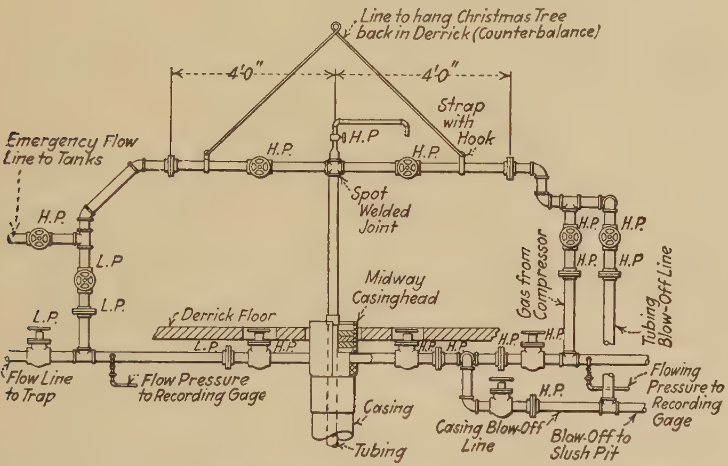
Line to hang Christmas Tree back in Derrick (Counterbalance)
4'0"
4'0"
Strap with Hook
Emergency Flow Line to Tanks
H.P.
H.P
H.P.
H.P.
Spot Welded Joint
H.P.
H.P.
H.P.
H.P
L.P
L.P.
L.P.
Midway Casinghead
Gas from Compressor
Tubing Blow-Off Line
Derrick Floor
L.P.
H.P.
H.P.
H.P.
H.P.
H.P.
Flow Line to Trap
Flow Pressure to Recording Gage
Casing
Tubing
Casing Blow-Off Line
H.P.
Blow-Off to Slush Pit
Flowing Pressure to Recording Gage

FIG. 151.—Layout of typical gas lift Christmas tree manifold. (*Bennett and Sclater.*)

Substantial, well-designed well-head equipment, in the interest of low maintenance cost and of continuity of operation, is desirable. Necessarily, the high pressures involved and the rushes of oil when starting call for heavy fittings to which no accident can occur at any stage of production.

The high pressures at present necessary to start wells with considerable fluid have been described, but it is only recently that the fittings on the derrick floor of a producing well have been given consideration from this angle. In time, the industry may find a method of equipment which will eliminate or minimize the high starting pressures now necessary, but until such time it is imperative to use connections and pipe of sufficient strength to stand the maximum pressure likely to be encountered.

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[1] PORTER, H. P., Tables for Figuring Tubing Submergence, as reported by A. F. HINTON, *Nat. Petroleum News*, p. 67, July 6, 1927.

[2] See *Petroleum Development and Technology*, p. 122, 1926.

It is not an uncommon thing to find 1,000-lb. working pressure valves and fittings used with a low-pressure cast-iron casing head forming the connection at the well. The vibration caused by the flowing operation when it starts is just as great as when a well flows naturally with the same pressure, and if connections at the well are not correctly and rigidly made, the operator is only inviting trouble sooner or later.

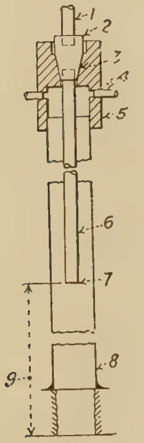

Fig. 152.—Tubing installation for gas lift. (*Bennett and Sclater.*)

Experiencing considerable difficulty in obtaining satisfactory heads for gas-lift work, a new type of head (See Fig. 152) was designed by the Marland engineers. It is of the "packless" type and has been found entirely satisfactory for all pressures used. The head consists of a forging turned and threaded to fit the casing oil string. The upper part of the head has a tapered seat turned and ground to a 30-deg. angle; a special collar ground to the same taper as the seat is used on the tubing. The weight of the tubing holds the collar in the seat. On account of the small area exposed to pressure, the head will seat tightly against extremely high pressures. Sufficient weight to hold pressures in excess of 5,000 lb. per square inch is provided by 2,400 ft. of $2\frac{1}{2}$-in. tubing. A heavy grease is smeared over the tapered collar before it is seated, forming a perfect seal. A common tubing spider and slips are set on top of the head when it is desired to change the position of the tubing.

Another type of head depending upon the weight of the tubing for its sealing action but fitted with packing is described a follows:

The "Blank" "short-type" tubing head allows the full weight of the tubing to hang directly on the packing for packing compression and seal. The top packing flange or follower is welded to the gate nipple, under a strengthening shoulder, and is a part thereof.

The rubber packing ring and standing flange are made up as a unit with the follower flange and gate nipple by means of tie bolts. The complete packing assembly and gate nipple are screwed onto the last joint of tubing, dropped into the tapered bowl, and the tubing allowed to hang on this assembly.

Packing compression is directly against the lower part of the heavy gate nipple, and is not against the tubing. This eliminates the danger of "bottle necking," "swedging," or otherwise injuring the pipe.

The tubing head bonnet may be screwed down on top of the packing follower to prevent the tubing from lifting under excessive pressures or expansions. Tubing slips are set in the spider with the handles safely accessible at the mouth of the bowl. The inside diameter of tubing head is the same as the inside diameter of the casing.

Traps and Separators.—Oil and gas separators have proved themselves of especial value in connection with wells operated by the gas lift. The necessity of providing some sort of gas-tight reservoir for receiving the output of the wells flowed by this means, and the requirement that such a reservoir be rigid and strong enough to withstand high pressures, suddenly applied, turned the attention of the operators to the oil and gas separator as the piece of equipment most likely to meet their needs. That this judgment was warranted is amply evidenced by the extensive use of separators in all gas- or air-lift fields. In this service they are subjected as part of their daily performance to frequent and severe applications of pressure, as in "rocking," often greatly in excess of their rated load.

Oils with high surface tensions show a tendency to liberate gas used for flowing more rapidly than oils having low surface tensions. This has an appreciable effect on the gas factor. It also has considerable effect on the design of traps, or separators. In the Panhandle field, owing to the high surface tension of the oil, complete separation can be effected by using "gun-barrel" tanks without the use of baffles. Condensate taken from gathering lines connected with such tanks is water white in color, indicating complete separation. In other locations where oils have low surface tensions, traps with much baffling are required to break down the frothy mixture and liberate the gas. This is especially true of wells of large capacity where high velocities exist.

As stated by C. P. Buck:[1]

"The fixed gases in Seminole crude are peculiarly persistent and the effect is noticed long after the oil has left the producer's tanks. This situation undoubtedly forecasts a serious problem of successful conservation that lies ahead as wells go deeper."

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[1] Buck, C. P., Evaporation Loss Control in the Producing Division, *Nat. Petroleum News*, p. 256, Sept. 21, 1927.

"From the producer's angle, the air-gas lift intrudes another problem—that of elimination of the air or gas from the oil in as great degree as possible before running to stock tanks. This calls for care in selection of the type of separator installed."

"With deeper wells, the air or gas lift is becoming of prime importance and of necessity the gas trap or separator, either without or with the flow tank, is an essential part of the tankage system. Where gas is used as the lifting medium and the cycle is a closed system, wherein scrubbed gas from the separator goes first to the natural gasoline plant where gasoline fractions are knocked out and then is returned to the compressor to be cycled through the well, evaporation loss is eliminated in this first stage of production."

"If, however, air is the lifting medium, and is merely scrubbed in the separator and then exhausted into the atmosphere, the loss of gasoline vapors may readily assume such proportions as to cause a serious dissipation of valuable gasoline. It is not only difficult but dangerous as well to attempt high compression of air-gas vapor or air-vapor mixture. The mixtures very readily become of such proportions as to be violently explosive. Naturally, the gasoline plant must exercise great care in handling vapors from the air lift, and must keep a careful check on the air content. Even so, the operation is an expensive one and wasteful of compressor power and capacity. Continued use of air as the lifting medium indicates the essential necessity of study to overcome gasoline loss in this operation."

In earlier fields it was the custom to place one battery of tanks and one gas separator in the center of the lease, and permit all flow lines to be connected thereto. A study of producing conditions has revolutionized this practice, and it has been found advantageous to place a single gas separator near the individual wells, and relieve the flow lines of the gas as rapidly as possible. The common sight is now to find each well with its individual gas separator and the flow line from the separator to the battery of storage tanks is laid as straight as possible in order to eliminate any resistance caused by elbows and bends in the lines.

Miller[1] states:

"In order to separate the gas from the oil and to recover the gas, it is necessary to flow the mixture of oil and gas from the well into gas traps or separators. Vertical cylindrical traps capable of withstanding pressures ranging from partial vacuum to 50 or more pounds per square inch and actuated by internal floats or external mechanical contrivances are used for this purpose in California. The majority of gas traps are located at an elevation above the derrick floor so that the oil will flow by gravity to the gage tanks and thus reduce the back pressure on the well to a minimum. Sometimes the traps are located in the derrick 20 to 30 ft. above the derrick floor on a platform made by placing timbers across the derrick girts. More often they are situated on a separate platform immediately outside the derrick."

"The height to which gas traps should be elevated depends upon the location of the gage tanks and upon the well fittings and flow line from the tubing head. For efficient operation, the oil line from the top of the tubing to the gas trap should be free from right-angle bends and no part of the line should be horizontal. Abrupt changes in the direction of the flow of the oil and gas mixture from the well introduce friction and create back pressures on the well. Horizontal lines allow the gas to separate from the oil and flow along the upper part of the line; by-passing of the gas in the lead line from the tubing head to the gas trap decreases the overall efficiency of the gas lift. For best results the flow line from the top of the tubing to the gas trap should be goosenecked. In one instance, the daily production of a 350-bbl. well was increased 266 bbl. by removing one 90-deg. ell from the flow line between the tubing head and the gas trap and installing a gooseneck flow line in place of the horizontal line with its vertical riser."

The use of a lead line from the well to the trap, much larger than the flow pipe in the well, is also to be avoided as a separation of the gas and fluid prior to delivery at the trap results. This creates an unnatural surging which automatically lowers the efficiency of the operation. It is, therefore, recommended that valves and fittings in the Christmas tree and lead line be of the same size as the flow pipe.

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[1] Miller, H. C., Mechanical Installation for Gas-lift Pumping As Practiced in the California Fields. *Petroleum Development and Technology*, p. 85, 1927.

In the Seminole fields, traps were usually placed on elevated platforms adjacent to the derrick and high enough to permit the oil to flow by gravity to the stock tanks. Traps varied in size from 4 by 12 to 8 by 20 ft. Common commercial traps and separators were used.

S. F. Shaw[1] states, in regard to this matter:

"Traps were placed close to the well, and all right-angle bends feasible to remove were eliminated, as was done at Tonkawa and Braman last year, which resulted in notable increases of production. It became the practice of the Carter Oil Company, to equip wells flowing naturally with traps in this manner, and in four cases, increases of 2,000 bbl. per well per day or more were obtained by this change alone without the aid of compressed air from the compressors. It should not be assumed, however, that placing the trap close to the well will always result in increased production, since this will be governed largely by the conditions obtaining for each individual well."

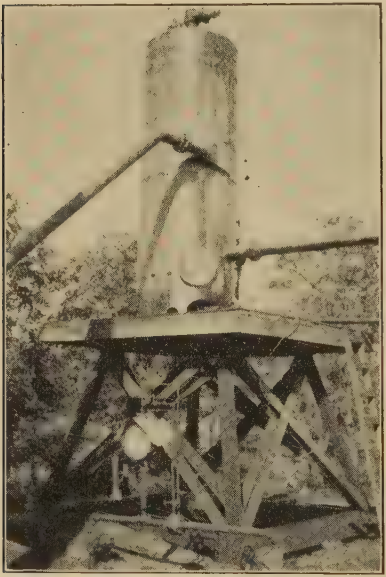

FIG. 153.—Typical separater installation, Bowlegs Field.

Figure 153 shows a National separator as mounted at a well of the Bowlegs Field. The input meter is shown below the platform.

Flow Lines.—A common point often overlooked or not given proper consideration is the size of the lead line from the well to the flow tank.

While the general trend at present is to place the flow tank as close to the well as the rig and other circumstances will permit and to use an individual tank for each well of any appreciable size, nevertheless many operators still hold to the idea of grouping wells into one central flow-tank battery. When this is done, the lead lines should be of ample capacity and as direct as possible, bending the pipe in preference to using fittings where this can be done and, in general, avoiding all pockets in the line which might cause surges. The steadier the pressure and the more constant the conditions of the well the more satisfactory will be the functioning of the gas lift.

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[1] SHAW, S. F., Air-gas Lift Practice in the Seminole Field, *Petroleum Development and Technology*, p. 100, 1927.

The pressure necessary to lift the gas and oil in a vertical direction sufficient to put it into a tank is much less than is necessary when the oil has had a chance to settle to a lower part of a horizontal run of pipe, as in a long lead line, and then have to go through a vertical run to flow into a tank. The operating pressure is also more uniform.

As stated by Pierce and Lewis:[1]

"As the velocity toward the top of the well becomes increasingly greater, the factor of frictional resistance is of even greater moment at the surface of the ground than in the well itself. Shaw has called attention to surface equipment that has been designed to reduce frictional resistance to a minimum and incidentally to reduce the back pressure at the top of the flow column in the well. This is applying correct and acceptable practices which have been used in the lifting of water, where the equipment for separation of air and water has received close attention. The value of reducing frictional resistance at the top of the well by having large flow lines and separating the gas from the oil as close to the well as possible is exceedingly important, as can be shown by theoretical considerations backed by experience; for example, if the flowing pressure is 20 atmospheres and the pressure at top of the flow column in one case is 4 atmospheres, and in the other case 2 atmospheres, the expansion in the first instance is five times and in the second instance ten times, with a resultant doubling in energy delivered. Of course, the useful work delivered is not doubled because of the increased velocity, but the overall efficiency in almost every case will be increased considerably by keeping down the top pressures which can be effected by proper design of surface flow equipment. The flowing pressure is likewise reduced to an important extent."

In some cases, flowing against a back pressure has retarded production and operators have even by-passed gas traps and flowed directly into lease tanks, which has increased production.

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[1] PIERCE, H. R., and J. O. LEWIS, "Principles of Air-gas Lift As Applied to Oil Production," *Petroleum Development and Technology*, p. 9, 1927.

So sensitive is the flowing balance with no surplus pressure available that all swings, right-angle bends, etc., should be eliminated. This is accomplished, in some cases, by welding the flow line to the side of the casing at a point in the cellar and coming off at an angle to the edge of the derrick floor, and thence flowing the oil directly into vapor-proof stock tanks. In this practice, all swings possible are avoided and only the minimum slippage in the line is allowed by keeping the oil moving in an upward direction until flowed into a tank where the lift effect is not required.

In the usual connections, one finds a 90-deg. tee at the top of the casing, one or two more 90-deg. tees with possibly a 45-deg. branch between the casing head and the trap or flow tank, two and possibly three tees making up the riser where the oil enters the trap. At each tee the fluid encounters additional frictional resistance which reduces the energy. Wells formerly rigged as above described have increased their flow by having the pipe fittings changed from 90- to 45-deg. tees with the consequent reduction of friction. In rigging up wells with this equipment it seems advisable to limit the sharp turns in the lines of flow, making all necessary turns of as large radius bends as possible. The use of 45-deg. connections is much better practice than tees or short-radius elbows.

The advantages of the shorter flow lines and the relieving them of the gas as soon as possible are manifold. When oil and gas flow through a line there is a different speed in their respective rates of progress. This is caused by the difference of densities of the oil and the gas; it is termed "slippage." The different rates of progress in the line cause friction and resistance and when the gas is removed from the line close to the well these factors are eliminated and in many cases the daily production of the well is increased.

As stated by George Reid:[1] "Gas-lift engineers in the Seminole area have proven by repeated demonstration that the elimination of angles and sharp turns in the flow lines leading from the well head to the separations or traps is a very important consideration. In other words, late efforts have been toward the removal of sharp turns, so that when the fluid discharges from the casing its course of flow may be as straight as possible to the point of discharge at the tank or separator. In many instances separators have been placed very close to the derrick and erected as high as 20 to 30 ft. in the air, so that the discharge from the casing will be very nearly vertical from the derrick floor to the separator where the fluid is discharged, for the purpose of creating as little friction as possible and to keep the oil and gas or air and oil in suspension or intermixture. Where horizontal lines are used, the gas has a tendency to rise to top with the result that the movement is slow. Sharp angles being eliminated, the surface equipment causes little back pressure to be exerted against the flow."

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[1] Reid, George, Efficiency of Air-gas Lift Proven at Seminole, *Oil Weekly*, p. 107, Aug. 19, 1927.

"Discharge lines leading from the separators are also made very large, often 8 or 10 in., depending upon the amount of fluid to be handled, in order that there will be no back pressure created on the trap and, consequently, upon the sand. Some distance from the trap these large lines are reduced to the usual size of pipe line required to handle the volume of oil produced in conducting this oil to the flow tanks. Operators using this type of hook-up install one small separator at each flowing well. Other operators do not regard the possibility of back pressure with as much seriousness and conduct the production from a number of wells to centrally located separators of large dimensions. Often these large separators handle the production from as many as four wells. In the event the wells are flowed by air pressure the separated air, with some gas mixed with it, is conducted away from the trap and up into the air 30 to 50 ft. and dissipated into the atmosphere. Where pressure flowing is accomplished by means of compressed natural gas, the gas from the separators is conducted to the near-by compression plant where it is recompressed, cooled, and the condensed gasoline removed, and the gas recycled into the oil-bearing horizon."

The principles described above are illustrated in many of the figures which show the trap settings and in the section on the subject of Well-head Connections.

Naturally, raw gas lines from trap to compressor inlet are subject to condensation troubles, and the same precautions as to pockets in lines that are used in gasoline plant practice are necessary here. Where pockets are unavoidable, automatic drips must be installed, for, where liquid collects in the line, high pressure is built up on the trap until gas is forced through the pocket and, in addition, the delivery of gas to the compressor pulsates as each charge of gas passes through the liquid of the pocket.

Along the same lines of distribution, trunk lines for gathering gas are more serviceable and less expensive than single lines from well to compressor, and, of course, to measure the quantity of gas delivered from the well, there should be installed a suitable orifice meter where gas from trap enters the trunk gathering line.

Notes on Application of Air or Gas Lift.—The possibilities of increasing production of oil by use of the air or gas lift are greater than generally supposed. The term "gas lift" will be employed to refer to either air or natural gas, whether or not compressors be used to compress the gas or whether the gas be that which is dissolved in the oil. Any well that is brought in for an initial production of 500 bbl. or more per day is a proper subject for investigation, with a view of installing an air or gas lift.

When a well is first brought in, if at all possible, the rock pressure and volume of gas should be determined, as well as the quantity of oil and water. If to these data there be added the depth of the well and diameter of the oil string, the engineer is in a position to determine whether a gas lift will operate successfully.

In order to conserve the gas in the pool, a well should be tubed as soon as possible so that the consumption of gas is reduced as nearly as possible to the quantity necessary to raise the oil to the surface. This quantity cannot, of course, be reduced to a point that is less than the amount dissolved in the oil produced. In many fields, the quantity of gas dissolved in the oil is several times that which is required to lift the oil to the surface; yet, under our present method of flowing wells, several times the quantity dissolved in the oil actually raised is allowed to escape. As brought out by Shaw:[1]

Assuming that a well has been brought in for an initial production of 2,000 bbl. at a depth of 2,000 ft. and at initial pressure of 700 lb. per square inch, it is possible for 140 cu. ft. of gas to be dissolved in every barrel of Oklahoma crude, 31° A.P.I. By extending the curve given by Dow and Calkins in United States Bureau of Mines *Bulletin* 2732, February, 1926, it is possible to show the decrease in dissolved gas content as the pressure decreases. Tabulation is given below of the quantity of dissolved gas, as well as the quantity of gas required to raise a barrel of oil to the surface under certain assumed conditions:

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[1] Shaw, S. F., Principles of the Air and Gas Lift, *Oil and Gas Jour.*, p. 382, June 16, 1927.

Quantity of Gas That Can Be Dissolved in 1 Bbl. of Oklahoma Crude at 31° A.P.I. and Quantity of Gas Required to Lift 1 Bbl. to the Surface

Depth	Pressure, pounds per square inch	Cubic feet dissolved in 1 bbl. oil	Feet submergence of oil at 0.9 specific gravity	Feet lift
2,000	700	140	1,790	210
2,000	600	120	1,535	465
2,000	500	98	1,280	720
2,000	450	88	1,150	850
2,000	400	78	1,025	975

Depth	Cubic feet of gas required to lift 1 bbl. to the surface		Percentage dissolved gas compared to the quantity required
	At 100 per cent	At obtainable efficiency	
2,000	8.06	12.40	1,129
2,000	18.52	29.54	406
2,000	30.12	51.05	192
2,000	36.63	65.41	134
2,000	45.67	89.59	87

"Assuming that the well has been properly tubed, the gas that can be dissolved in 1 bbl. of oil at 700 lb. pressure per square inch is 11.29 times the amount required to lift 1 barrel to the surface. At pressure of 450 lb. the quantity still dissolved in 1 bbl. of oil is slightly greater than that theoretically necessary to raise it to the surface, but with pressure reduced to 400 lb. there is insufficient gas to cause the well to flow steadily and it is probable that the well will begin to flow by 'heads,' although a fairly continuous flow might result for a further period if sufficient gas can reach the well from some distance. This use of gas, however, would rob the distant oil of its dissolved gas and prevent much of it from flowing through the sands to the well. The time interval between heads results from the necessity of the oil to rise in the well to such a level that the gas accumulated and dissolved in the oil becomes sufficient in quantity and pressure to flow the well for a short period, and after the gas has escaped the fluid level again drops down."

"At this stage of flowing by heads, or even better, before this stage is reached it is probably advisable to consider the installation of a compressor to furnish the additional quantity of gas necessary to make up the amount which the oil at that time fails to contain in a dissolved condition to permit the gas lift to operate continuously and efficiently. The quantity of gas necessary to add by means of the compressor will gradually increase as the dissolved gas becomes depleted, until finally the fluid level drops to a point where the gas lift cannot operate to advantage. When this stage is reached it is advisable to get the well on the pump as quickly as possible."

"A well with initial production of 2,000 bbl. per day which has declined to 200 or 300 bbl. per day can often be restored to 500 bbl. or more per day and, in some cases, has been raised to 1,000 bbl. per day."

"Examples of production restored in this manner are found in Braman, Garber, Long Beach, Santa Fe Springs, Smackover, and Tonkawa, and it is to be expected that further similar examples will occur in such places as Big Lake, Lisbon, Panhandle, Rainbow Bend, Spindletop, Urania, and Wewoka."

As to the ultimate recovery phase of the air-gas lift applications, many opinions exist. Pierce and Lewis[1] gave the following discussion of this matter, as relating to back pressure and its use:

"It seems doubtful whether the gas lift has any important effect on recovery other than the back pressure applied against the face of the sand; therefore, the discussion of the air lift upon efficiency of oil recovery comes back to the same controversial question as to the use and utility of the back pressures. Without presenting evidence or analytical reasons for their opinions, the writers merely wish to state that they believe that the back pressure will be beneficial, or not, wholly in accordance with the degree of pressure applied, and the manner of applying it, and in relation to the location conditions. When the junior author discussed this subject in *Bulletin* 148 of the Bureau of Mines, he called attention to the fact that too high a back pressure would be detrimental, but, on the other hand, there was much evidence that at some point there would be a back pressure for each condition which would be beneficial just as there has been shown to be an optimum submergence for the air lift with relation to the other concurrent conditions."

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[1] Pierce, H. R., and J. O. Lewis, Principles of Air-gas Lift As Applied to Oil Production, *Petroleum Development and Technology*, p. 19, 1927.

"A high back pressure prohibits the full expansion of gas and thus lessens the amount of energy delivered by it. On the other hand, if the gas is allowed to expand to its maximum extent, the additional work delivered will be largely consumed in greater velocity and, therefore, greater friction, so that additional useful work theoretically available will be small. Furthermore, there is good reason to believe that the higher velocities created will result in greater slippage of the gas through the sand and it has been shown by Henry L. Doherty that the taking the gas out of solution from the oil will also have an important and seemingly detrimental effect on the physical properties of the oil."

"These lines of evidence are reasoned out by a careful consideration of the results from applying back pressure both under artificial pressure and under natural pressure. The seemingly irreconcilable results reported by various observers of back pressures both when used with air lifts and elsewhere can be explained by the fact that account must be taken of the limited range in which back pressure can be advantageously used, which if either less or more, will be harmful."

"If the writers are correct in their conclusions, the effect of the air lift upon oil recovery is to be measured by the back pressure created by it and the air lift should be designed and operated at a pressure to conform with the back pressure giving the best results in oil recovery."

"These considerations, however, are limited by the practical ones of the competitive conditions at the well and, therefore, the necessity for getting the highest daily production. Not until a great deal more observational data has been collected and analyzed can it be known how to work out the use of back pressures and how to design the air lift so as to get the back pressures desired, and at the same time have an efficient air lift within the limits imposed by the size of the casing and other economic and practical conditions."

"It may at first thought seem that the air lift, which in a deep well may be imposing several hundred pounds of pressure on the well, would create a back pressure instead of lessening the back pressure, but, actually, a naturally flowing well may have a greater back pressure on the sand than is necessary to lift the oil by the air lift and this is even true with a pumping well. If for any reason the oil coming into the well is not removed as fast as it enters, it heads up in a well and exerts a big back pressure. This will take place if the pump has not sufficient capacity or in a flowing well if the pressure and volume of the gas does not supply enough energy to lift the oil rapidly. Under these conditions the air lift by removing the accumulated column of oil will actually reduce the pressure on the sand."

In some locations oil-bearing strata are immediately above and in direct contact with water-bearing formations. This is particularly true in the Panhandle area where the top of the water-bearing stratum exists at approximately sea-level elevations. Above the oil formation in this region there exists a gas-bearing stratum. This upper gas formation, while separated by as much as 200 ft. from the oil, is open to the oil formation in spots.

Where wells have been producing by swabbing heavily or by flowing through a 6⅝-in. oil string with extremely large gas factors, the pressure in the upper gas region adjacent to the wells has been dissipated and the water surface has risen under hydrostatic pressure, due to the decreased gas pressure above.

The extreme reduction of this pressure has caused the water to cone up at the well and eventually break through the oil strata, trapping off the oil and causing the well to produce water. If swabbing is continued under these conditions, or the natural flow allowed to take place, the well will continue to produce nothing but water. This will also occur if a well on the gas lift is improperly handled.

Conditions such as described above can best be remedied by use of the gas lift under back pressure. In most cases where proper installation is made, the resistance to flow furnished sufficient pressure on the sand without the necessity of surface control. The best arrangement for flowing a well producing water is to pump the gas down between the casing and tubing and produce the oil through the tubing. The tubing may be raised off bottom to a point where the fluid head between its lowest extremity and the water surface plus the additional head required to flow the oil through the tubing will exert sufficient pressure on the sand to prevent the water from coming up through the oil. If the tubing is maintained too close to the water level, it will tend to make the well produce water to the exclusion of oil. Where a proper pressure is maintained to keep the water level down, the entrance of oil to the well will take place over the top of the water surface by lateral travel instead of cross-bed travel and the water will be held in check. When water breaks through and wets an oil-producing sand, it excludes the oil by virtue of its greater surface tension. Water also migrates through a sand with less resistance on account of its greater fluidity.

As stated by Bennett and Sclater:[1]

"The gas lift can be very effectively used to increase the ultimate production of a field in which bottom water encroachment is encountered. Pressure and flow conditions may be so regulated that back pressures on the formation sufficient to hold down bottom water coning can be maintained, allowing lateral drainage of oil above the water plane. This method of operation has been in successful use for the past year in the Panhandle. A well in this district, that made 100 per cent water in December, 1926, has averaged 590 bbl. of oil per day since that time. The gas lift has also made economical recovery from wells producing as much as 90 per cent water. Some wells in this class produce as much as 2,500 bbl. of fluid with but 250 bbl. of oil. A pump cannot be made to handle this volume of fluid. Large-capacity pumps set in the casing by slips and packers and operated without tubing are, however, being used for pumping large quantities very successfully."

"In some wells a control of pressure is extremely critical. A few pounds increase or decrease on the sand will materially change the oil and water ratio where wells are producing some water. In one particular instance, a well in the Panhandle district was producing 680 bbl. of oil and 66 per cent water by swabbing. This well was fitted with 4½-in. tubing to within 400 ft. of the bottom. Gas was introduced between the casing and tubing and the fluid flowed through the tubing. This well has since been producing 1,700 bbl. of oil per day on the gas lift and the water percentage was reduced to 25 per cent, where it has remained constant. The pressure required to flow the well is approximately 160 lb. The estimated weight of the fluid column between the bottom of the tubing and the top of the water-saturated formation is 150 lb. Under this condition, the total pressure on the water front is 310 lb., which is sufficient to prevent it from coning up through the oil-bearing formation. Lowering the tubing increases the resistance to flow, on account of the greater distance the fluid must travel."

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[1] BENNETT, E. O., and K. C. SCLATER, Some New Aspects of the Gas Lift, *Petroleum Development and Technology*, p. 115, 1926.

The following practical considerations on the theory and application of the gas lift are taken from the paper presented by E. O. Bennett and K. C. Sclater[1] at the 1927 meeting of the A.I.M.M.E. Petroleum Division, and covers some of the experiences obtained by the Marland engineering force:

"There are so many variables which enter into the design of a gas lift that each and every well must be considered as an individual problem and analyzed accordingly. A careful study of results obtained by varying the controllable conditions will furnish data for increasing the efficiency of an installation that cannot be successfully worked out by theoretical equations. The important factors entering into the design of gas lifts for oil wells are:

"*a. The Ability of the Sand or Formation to Produce Oil.*—The ability of the sand or formation to produce oil is dependent upon the porosity, thickness, and the saturation of the formation, and the gas pressure existing in it, also upon the viscosity and surface tension of the oil. The ability of a well, which will not flow naturally, to produce oil is determined by the rate at which oil will fill a definite size casing.

"*b. Pressure in the Oil-producing Formation.*—At the present time the actual pressure in the oil-producing formation must be determined from the observed pressures at the well head, the amount of fluid in the hole, and its specific gravity.

"*c. The Solubility of Extraneous Gas in the Oil to Be Flowed.*—Solubility affects the viscosity and surface tension and also the resistance to flow, which is dependent upon these factors. It also has some effect upon the natural-gas factor (cubic feet of gas from the formation per barrel or oil lifted).

"*d. The Amount of Natural Gas per Barrel of Oil in the Formation.*—This item is called the 'natural-gas factor.' The amount of extraneous gas required in a gas-lift installation depends largely upon the natural-gas factor existing, since the total amount of energy must be supplied in the form of compressed gas, in order that a given weight of oil may be raised.

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[1] Bennett, E. O., and K. C. Sclater, Some New Aspects of the Gas Lift, *Petroleum Development and Technology*, p. 115, 1926.

"*e. Surface Tension.*—Oils with high surface tensions show a tendency to liberate gas used for flowing more rapidly than oils having low surface tensions. This has an appreciable effect upon the gas factor. It also has considerable effect upon the design of traps, or separators, used to separate the oil and gas at the surface of the well."

There is a larger field for air or gas lift in smaller wells, for air will pump a well with 10 ft. of fluid in the bottom. It is true that the efficiency of the air lift will be much lower in this case, but not so much different from the mechanical efficiency of ordinary pumping methods. Practically all well problems are a matter of compromise, anyway, for none of the factors is always ideal—"get the oil and get it continuously"—even though efficiency may be a little lower. Power costs in pumping small wells are not excessive anyway and with residue gas fuel, or other cheap power, a layout with slightly lower efficiency that maintains an increased production has a greater overall efficiency.

The cost of an air installation for small wells compares favorably with costs when equipped with customary methods, particularly in flush fields where usually several kinds of pumping equipment are used in a well before it subsides into a working barrel pumper.

S. F. Shaw[1] states, relative to the small well problem:

"Considerable difficulty has been experienced in pumping small wells on the beam in the Seminole field, and the writer was requested to determine whether these wells could be operated by means of the air-gas lift. Two wells were equipped with tapered tubing to determine whether this was practicable. The results were quite satisfactory and subsequently several other wells were equipped in this manner with fully as good or better results than for the first wells. One well with a production as small as 10 bbl. per day was operated very satisfactorily, and several wells ranging from 20 to 350 bbl. are now being flowed in this manner. The quantity of oil lifted per day was not increased except in one instance, but the quantity of gas sent to the well has been reduced to about one-half the consumption formerly employed when lifting between the tubing and casing."

[1] SHAW, S. F., Air-gas Lift Practice in the Seminole Field, *Petroleum Development and Technology*, p. 100, 1927.

"As wells become smaller in production, the pressure drops, the lift increases, and the quantity of gas required to lift a barrel of oil is greatly increased over that necessary for a large well, and this quantity increases to an abnormal extent if the lifting be done through the same eductor as when flowing a large well. A consumption of 50,000 cu. ft. per barrel could easily be reached in flowing a 10 bbl. well through the annular area between the 2 or 2½-in. tubing and the 6⅝-in. casing, whereas a proper size of taper-tubing string would operate on 10,000 cu. ft. per barrel or less, at 50 lb. pressure per square inch, when flowing a well of this size."

"The conditions of pressure or submergence of lift, quantity of fluid, and quantity of gas accompanying the oil have a close bearing on the proper design of tapered tubing, and unless a nearly correct design is obtained it is best not to use this method of tubing since the quantity of gas consumed per barrel of oil may become excessive and production may be considerably reduced."

And, again:

"In Seminole, we have operated wells on tapered tubing strings ranging from 400 down to 10 bbl. with excellent results, and at an expense considerably less than can be done with the beam pump, particularly in these wells where holes are likely to be crooked, causing excessive wear on rods and tubing. The time off from pumping on gas lift is, perhaps, not 20 per cent of that when on the beam. To be economically operated, however, wells of 100 down to 10 bbl. should be handled with compressed air or gas from direct-driven gas engine compressors, particularly when ranging from 25 to 10 bbl. Experiments now being conducted indicate that intermittent flowing of wells ranging in production from 25 down to 5 bbl. or less will be more economical than continuous flows, though in these wells the greatest economy is reached if the wells are also equipped with tapered tubing."

"The deciding factor in operating small wells is one of capital expenditure. If a lease is already provided with central power and pumping jacks, it is questionable as to whether a compressed air plant could be advised. If the lease is not already provided with any kind of pumping plant, probably air lifts would give greater production at less cost than ony other means, assuming, of course, that the installation and equipment of the wells be done in the proper manner. Wells of 1,500 ft. in depth would require less than one-third the quantity of compressed air or gas per barrel of oil that is required at Seminole, under equal conditions of pressure."

Wells of low production possibilities, especially older wells that produce very little oil can be "blown" by a specially designed installation. The idea here is to inject a sudden shot of high-pressure air or gas and literally blow the accumulated oil to the surface through the tubing. The well should be opened to the high-pressure air or gas only a few minutes, otherwise production will be decreased by forcing some of the oil back into the producing formation with the possibility of plastering the wall with mud or sediment.

Not all fields are proper subjects for an application of the lift principle. Some oils, especially the asphaltic base oil, form bad emulsions which are extremely hard to demulsify, if at all. If water is present, even in small amounts, the use of an air-gas lift installation serves as a means of perfect agitation. The paraffin base oils are the least subject to the formation of untreatable emulsions.

One quotation concerning the inapplicability of the lift installation will be made:

"The McCamey district has cut oil which presents extreme corrosion difficulties when air is used."

"Another good example of a district not suited to air- or gas-lift methods is the Muenster pool, Cooke County. Low fluid content has also caused abandonment of the attempt to flow wells by air in this field. Strobe and Strobe put in a plant consisting of one Ingersoll-Rand Imperial type compressor, designed to operate at 300 r.p.m., 300 lb. pressure, driven by a 75-hp. General Electric motor."

"Number 3 well, on the Koeltzer lease, was put on air on May 17, at which time it was making 120 bbl. In spite of the air, production gradually decreased so that on May 27 the well was making only 75 bbl. Number 4 was put on a little later when it was making 250 bbl. This well was blown 11 days, at the end of which time it was making 175 bbl. In both cases, very little more oil was obtained from air than could be pumped, but with considerably more expense. So it was decided to abandon the idea of air lift. Number 3 well is now pumping 110 bbl. and No. 4, 140 bbl. Cost of putting air into the wells was about $1 per hour, whereas it is claimed that they can be pumped for 24 hr. for very little more than that. Wells in the Muenster field are about 1,660 ft. deep."

A. F. Hinton[1] gave the following discussion and graphs showing some characteristics of the gas-lift decline curves:

"A graph accompanying this article (Fig. 154) shows daily production history of one of the best wells in the 9-6 field and gives a good idea of a typical gas-lift decline curve. This well flowed naturally for about 33 days, getting up to maximum production of 8,000 bbl. Immediately after reaching this peak, the well went absolutely dead and ceased flowing very suddenly. Anticipating this development, the operators had tubing at hand and all preparations made for putting the well on gas, in two days had it back to 6,000 bbl. production, and got it up to 6,800 bbl. in about 10 days after it ceased to flow naturally."

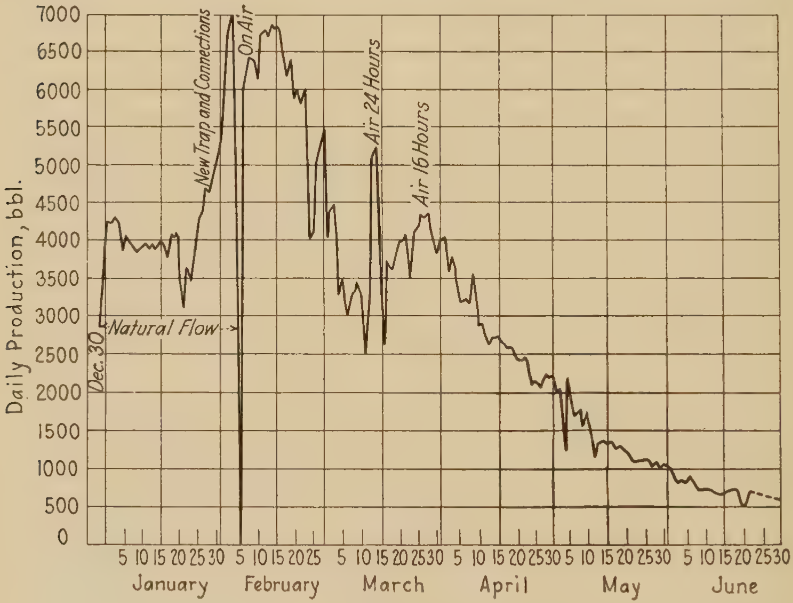

Fig. 154.

"Late in February and in March, the production curve shows violent fluctuations. At that time a serious crude congestion was taking place, and all operators were making efforts to hold back production wherever possible. In the case of gas-lift wells, this was accomplished by cutting off the gas at intervals and for varying periods, causing recurring peaks and valleys in the production curve. Late in March the well went on lift permanently. An inspection of the curve indicates that considerable production was lost by this pinching in process during March, as apparently the curve would have connected through from Feb. 25 to Mar. 25 without the intervening fluctuations. It is likely this production never will be regained.”

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[1] Hinton, A. F., Air-gas Lift Producing Two-thirds of Seminole Oil, *Nat. Petroleum News*, p. 49, July 20, 1927.

“When 6 months old, this well is still flowing 650 bbl. on gas lift. All told, it has produced approximately 500,000 bbl. of 41 gravity crude. Judging from the present course of the curve, it appears likely that in the next 3 or 4 months or a year from the time of its completion, it will have been pretty thoroughly depleted.”

“One remarkable feature of this well’s history is the large production gain brought about by changing the trap and connections. A separator was placed close to the well and all right-angle bends eliminated from the flow line. As shown on the chart, production jumped from 4,600 to 8,000 bbl. after this change was made.”

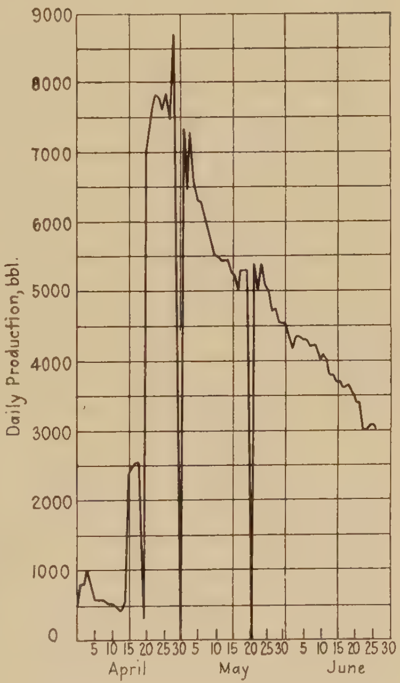

Fig. 155.

“Figure 155 is the daily production record of a Seminole well flowing naturally for 3 months and still making 3,000 bbl. a day in that manner. A comparison of the two curves indicates a very similar rate of decline between a flowing and a gas-lift well. Theoretically, the decline should be the same, if the gas-oil ratio of the natural flowing well is regulated to secure greatest efficiency and the gas-lift well is operated properly. In other words, a gas-lift well is simply a natural flowing well in which the impelling force has been artificially added.”

Brundred[1] gives the following summary of the lift practice in the Gulf coast area:

"It may be noted that expenditures of large sums for more or less permanent gas-lift equipment have been considered illogical. The average operator, therefore, considers quickness of installation, portability to a new field and salvage value rather than cheapness of fuel and other costs of operation. The direct result of this attitude is that by far the bulk of all installations has been steam-driven compressors."

"Another important factor influencing the use of steam is the necessity for fire protection in such closely drilled fields. For this purpose boilers with steam pressure constantly available must be erected. By the addition of one or more units to the boiler station, steam in sufficient quantities is available both for the compressors and the fire protection."

"The coastal area is perhaps the most completely electrified oil-field section of the United States, in that high-tension power lines form a veritable network of connecting sources of electric power, at a very favorable rate to the consumer. Such rate is surprising in view of the fact that all generating plants are steam driven. The availability of this relatively cheap power accounts for some of the recent installations of compressors belted to electric motors. The cost of operation is, however, hardly comparable with gas or oil engine-driven units."

"Practically all compressors installed to date, whether steam, electric, gas, or oil driven have had displacements ranging from 300 to 500 cu. ft. per minute, and little attempt has been made to centralize control in one large distributing plant serving a number of wells simultaneously. In fact it was practically an accepted fact in this area that it was essential to have one compressor to one well. Also little use has been made of the modern volume controllers for carefully apportioning the gas to each well. As a result there are practically none of the so-called 'central plants' operating a number of wells either with the loop system or header control house located near the plant."

"On account of the heavy type of oil produced, the large percentage of water present and the failure of the bulk of the oil companies to take advantage of the most modern methods, such as unrestricted flow pipes, traps set close to the derrick floor, and the use of volume controllers, little information as to the exact efficiency being obtained is available. In the few cases where this information is available, the results would seem to indicate that the wells in this area will require slightly higher circulated gas to oil ratios than that necessary in other fields. It must be said, however, that there is an insufficient number of installations where the input and output air is metered to make such a statement entirely conclusive."

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[1] Brundred, L. L., Mechanical Installation for Air-gas Lift in the Gulf Coastal Area, *Petroleum Development and Technology*, p. 68, 1926.

"Little attention has been paid to the Christmas tree installations in that the bulk of the wells 'on air' have used the original Christmas tree hook-up with which the wells were brought in. It followed that considerable difficulty was experienced in attempting to raise or lower tubing quickly as well as to start the wells on gas lift by rocking; the work being largely considered as experimental, few of the operators were willing to incur the expense of special gas-lift Christmas-tree layouts."

"The use of jets or other flow devices seem to be prevalent. Comparative data on the same well using first a flow device and later open-end tubing are not available and little experimental work of any kind has been conducted to date due primarily to the present low price of oil."

"Recent drilling has opened sands at a much greater depth than heretofore encountered and the task of pumping these wells, especially with the high percentage of water present, has become a distinct problem. It is believed that gas lift under proper control and with proper mechanical installations will, after considerable experimental work, prove to be of considerable aid in the solution of these problems. This area offers certain fundamental difficulties, not encountered perhaps in any other district; therefore, by experiment only, can the full value of this modern method of producing oil from deep sands be determined."

A. F. Hinton,[1] gave a very interesting summary of production practices in the Seminole area. The following quotations are from his article:

"Seminole production practice has now reached the state at which close study is required if the best method of keeping the wells on production is to be determined. It goes without saying that the problem of keeping wells producing goes hand in hand with the question of making a profit from their operation. Solution of the problem naturally resolves itself into a determination of lifting costs by various methods; the principal difficulty lies in accurately determining these costs."

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[1] HINTON, A. F., Pumping Gaining in Favor at Seminole As Well Production Declines, *Nat. Petroleum News*, p. 92, Oct. 5, 1927.

"Use of the air-gas lift, which has been responsible for more than 70 per cent of Seminole's production, has brought about many changes in organization and accounting methods, or at least it has pointed out the necessity of such changes if this method is to become a component part of future development and production programs. Companies that have not made these changes now find themselves able only with difficulty and many approximations to state definitely just how they stand after 15-months' operation at Seminole, and especially are they finding it difficult to state exactly how much it has cost them per barrel to lift the crude they have produced through gas-lift operations. The final problem, of course, is to determine when it becomes unprofitable longer to flow wells on lift, and the answer to this can be given only after considerable close study of conditions."

"There are only four generally used and recognized methods of obtaining production from oil wells: natural flow, pumping, swabbing, and air-gas lift. Enough experience has been gained with the first three time-honored methods to enable one to state with some degree of accuracy how much oil and at what cost per barrel they will produce. As for the last named, the youngest, but, as far as Seminole is concerned, by far the greatest of them all, no such confident statements can be made. It undoubtedly got the oil, got it in large quantities, and got it quickly, but whether it has been a blessing or a curse to the industry is now the subject of much conjecture."

"Had it not been for the gas lift, the Seminole district probably never would have reached 200,000 bbl. in daily production, as compared with its actual peak of 527,000 bbl. At its present age it probably would have been depleted 60 per cent, as against an estimated depletion of around 85 per cent for most properties in the older portions of the field. It is possible that more oil eventually would have been recovered from the field had gas lift not been resorted to, but it would have been recovered over a much longer period and at a very much higher cost. It is generally understood that Seminole was directly responsible for the severe reductions in Mid-Continent crude prices early this year, and it is altogether likely that these reductions would not have come to pass, or would have been less drastic, had Seminole never exceeded 200,000 bbl. a day."

"Therefore, gas-lift is credited with recovering several years' production in one, at a low per-barrel figure, but at the same time it is charged with breaking the market and to a certain extent disorganizing the industry in the Mid-Continent field. What many executives are now asking is this: Would we not have been better off if we had taken Seminole crude out slowly, even though at higher cost, if by so doing we had maintained a comparatively high price for our product? The answer to that, of course, lies with the individual company, and can be determined only by actual analysis of its operations."

"The chief difficulty in determining actual results of use of gas lift lies in estimating what the wells would have produced by other methods, had these methods been applied to the wells early in their history. Many wells have been taken off gas lift and put to pumping when they got down to the small production state, while many others have similarly been swabbed when the companies decided that it was no longer profitable to operate them on lift. These wells, of course, have not performed in a manner at all comparable to what they would have done had they been put on the pump or swab immediately at the close of their natural flow period. Inasmuch as practically all Seminole wells were put on lift as soon as they ceased flowing naturally, or immediately if they did not flow naturally, the only wells that have been pumped or swabbed have been those which either did not respond satisfactorily to gas lift or which had declined to the point where it was not economical to flow them any longer."

"One large company, in summing up, for its executive, results of its operations at Seminole has made an interesting study of its gas-lift work, comparing it with other production methods. This company invested about a half-million dollars in compressors and general air-lift equipment. Its air-lift production was slightly more than 60 per cent of its total production from the district. In comparing air-gas lift with other methods of production, this company estimates that, by swabbing and pumping, one-half as much oil could have been produced as was obtained by lift. This is undoubtedly a conservative estimate, as it is probable that not more than one-third as much oil could have been produced by the other two methods. For the purpose of this statement, however, this company estimates that it got 2 years' ordinary production in one."

"Up to the date when this report was compiled, the company's lift operations had totaled 3,600 well flowing days. Analyzing each well's history in an effort to decide whether it would have been pumped or swabbed, and at what periods in its history these methods would have been used, the report estimates that there would have been 2,420 swabbing days and 1,178 pumping days on these wells. Its operations indicate that it cost $35 per well per day to produce with gas lift, as compared with $75 a day for swabbing and $10 a day for pumping. On this basis, its gas-lift production was obtained at 4.4 cts. per barrel, while use of the other two methods would have resulted in half as much oil recovered at a cost of 13.5 cts. per barrel."

"Another company permits the publication of the following figures as to the operation of one of its gas-lift plants. This plant, which has twenty-one 80-hp. units, represents a total investment of $276,000. It has had about nine wells connected, and during the 4 months from July to October, inclusive, has had 1,064 well flowing days. In that period the plant has produced 1,213,000 bbl. net, an average of 1,140 bbl. per well per day. Operation and maintenance of the plant, not including well operation charges, has totaled $14,600 in the 4 months, or about $3,650 per month. Charging the plant with interest on investment and with depreciation sufficient to write it off in 2 years, total charges, including operation and maintenance, have been $66,200. On this basis, cost of operation only has amounted to $13.75 per well per day, and $62.20 per well per day with all charges included."

"Total lifting cost for this plant during the 4-month period, with all charges included, has been 5.5 cts. per barrel. Figuring only operation and maintenance charges, the oil has been brought to the surface for 1.2 cts. per barrel. If we make the highly improbable assumption that the same amount of oil could have been swabbed from these wells during the same period, it would have cost $79,800 to produce it, at a lifting expense of 6.6 cts. per barrel. It is probable that not more than one-half the amount of oil could have been recovered by swabbing or any other method."

"It must be borne in mind that the foregoing figures on lifting expense apply only to actual gas-lift plant flowing expense, and they must not be considered as representing the cost of producing Seminole crude. They do not include direct lease expense, development expense, original cost of leaseholds, office overhead, or any item of expense outside of the plant under consideration."

Recently, there has been a marked tendency on the part of Seminole producing companies, in the older portions of the field, to take the wells off lift and put them on the pump. This has been especially true in the Seminole City field, oldest and most settled of five fields. Some companies have selected certain wells for experimentation and have put them on the pump, while other similar wells have been equipped with tapered tubing and have been kept on gas lift, the idea being to ascertain definitely which of the two methods is the better and more economical. Other companies have abandoned gas lift altogether on many properties and are pumping all wells.

The general opinion among production men in the field seems to be that when a well gets down to around 200 bbl. daily it is time to take it off gas lift, because it is costing too much to operate. This view is not generally shared by engineers whose trend of mind and training lead them to a desire to be shown that the wells can be pumped as cheaply as they can be flowed, even on small production. The engineer's tendency is to continue to experiment with the wells until a way is found to keep them flowing profitably, while the production man believes in flowing them while the flowing is good and getting back to first principles as soon as he has convinced himself that they cannot be kept on gas lift longer with profit.

Pumping Seminole wells is fraught with difficulty, simply because of mechanical troubles, and not because there is any strange or mysterious reason why these wells should not pump so well as those in other fields throughout the Mid-Continent. Many of the wells pump quite successfully while they are pumping, but none of them is exempt from a great deal of down time, which causes them much lost production and adds greatly to the final lifting expense. In analyzing a pumping well's performance, its down time and consequent loss of production must be taken into account if a true picture is to be obtained. When a pumping well is pumping, it undoubtedly lifts oil very cheaply as compared with any other method, but the difficulty at Seminole is to keep the beam in motion.

To show the idea of the change from the lift installation to pumping equipment, the following items were extracted from an article A. F. Hinton:[1]

"Although the air-gas-lift method continues well in the lead in production methods in the Seminole district, there has been a marked increase in the past two months in the number of wells pumping, especially in the old Seminole City field. This has been partly due to removal of compressor equipment to the Bowlegs and Little River fields, to handle later developments there, added to which is the reluctance of executives to authorize purchase of additional equipment to keep the small production Seminole City wells on lift."

"Another explanation of the increase in pumping is that as the wells decline to small output figures, it becomes more and more of a problem to keep them operating profitably on lift. When this state arrives, and it becomes necessary to experiment, tendency of the production department seems to be to return to first principles and fall back on pumping, which they know to be an old reliable method. By doing this, the gas-lift engineer is prevented from getting data on well-performance under small production conditions."

"As one engineer expressed it, almost anyone could put the wells on gas lift and operate them successfully when the field was in its flush state, although in many cases wells might have made even more oil if the lift had been properly installed or closer attention given to pressure employed and volume introduced."

"When the wells have declined, however, and the fluid level drops, successful operation of gas lift demands knowledge of its laws and strict application of engineering principles. At this stage of the game it becomes necessary to experiment with different sizes of tubing, and with various shifts in compressor equipment. A number of companies, however, have become impatient with this experimentation, believing the gas lift a failure on small wells and have gone to pumping, although in all probability they could still be getting more oil at lower lifting costs by the newer method."

"Following is a comparison of the various production methods in the Seminole City pool as of July 15 and Sept. 15:

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[1] Hinton, A. F., Pumping Gaining in Favor at Seminole As Well Production Delines, *Nat. Petroleum News*, p. 92, Oct. 5, 1927.

	July 15				Sept. 15			
	Wells	Percentage of total	Production	Percentage of total	Wells	Percentage of total	Production	Percentage of total
Lift	162	52.0	79,889	74.9	133	41.4	54,921	71.7
Flow	19	6.2	19,136	17.9	9	2.8	4,335	5.7
Pump	62	19.9	4,667	4.4	110	34.3	9,484	12.4
Swab	24	7.7	2,994	2.8	33	10.3	7,914	10.3
Off	44	14.2	......	....	36	11.2		

"Average production per well on the pump is so small, and the wells are down so much from various troubles that lifting costs are very high in most cases. One of the principal causes of trouble is rapid wearing out of rods, as these are subjected to terrific strains in a 4,300-ft. hole. Crooked holes, of which there are many, also cause rod trouble as well as tubing trouble. Another source of down time is the shifting sand in some portions of the field. This sand floats into the well with the oil and causes a very rapid wear on cups."

"Tendency in the field seems to be to put a well on the pump when it has gotten down to around 150 to 200 bbl. on gas lift, although there are of course many wells making less than that and still on lift. Gas-lift engineers are practically unanimous in believing that the wells now pumping could be making more oil and producing it at less cost and more steadily if they were still on lift."

"However, at somewhere around 150 bbl. production, it is likely that oil can be lifted as cheaply by pumping as by gas lift or it could be if the well could be kept pumping constantly, instead of being down from one-third to one-half the time."

"One large company has figured that it costs about 3 cts. per 1,000 ft. to compress air or gas with a gas engine direct-connected compressor. A 100 bbl. well will require about 2,500 cu. ft. per barrel, or 250,000 cu. ft. total. At 3 cts., this means $7.50 a day, or 7½ cts. a barrel operating cost. To operate a 10-bbl. well, to illustrate how operating costs rise as production diminishes, requires about 10,000 cu. ft. per barrel, or 30 cts. a barrel cost."

"According to the same company, compression costs 7½ cts. per 1,000 ft. where electric power is used. This would mean an operating cost of 18.75 cts. a barrel for the 100-bbl. well and 75 cts. a barrel for the 10-bbl. well."

"On an actual pumping well, which of course cannot be taken as representing the entire field, but which probably is typical, actual lifting costs over a 3-month period ran from 12.5 to 22.3 cts. a barrel. Total operating costs, however, in which are included labor, overhead, and lost oil on account of down time, ran from 31 cts. to $1.04 a barrel. The figures on this well are as follows:

Month	Pumping days	Down days	Average production per day	Lifting cost	Operating cost
June	21	3	202	$0.125	$0.31
July	19	12	186	0.223	1.04
August	26	5	113	0.159	0.41
Total	66	20	167	0.169	0.586

"Up to Sept. 12, the well had been down 4 days and 7 hr., and had produced 628 bbl. or an average of 78 bbl. daily during the 8 days it was pumping. Indications are that its operating cost for September will be in the neighborhood of $1 a barrel."

"Another well was taken off gas lift when it was making 200 bbl. daily, and put on the beam as an experiment. It was cleaned out before being put to pumping. For the next 3 weeks its average production per pumping day was 75 bbl., and its highest production on pump was 129 bbl. It was down nearly half the time during this period."

"In another instance, a company drilled in a new well with only a small showing of oil. Efforts to pump it failed and the production department was about ready to give it up as a bad job and call it a 'dry hole.' The air department, however, was allowed to experiment with it, and it is now flowing 125 bbl. daily on lift."

"In trying to keep small wells operating economically on lift, considerable experimenting is being done with tapered tubing, or in changing size of tubing to reduce the annular space between the tubing and casing, the idea being to reduce amount of equipment necessary to operate the wells while keeping production up. In many cases, this necessitates reversing the flow from the casing to the tubing. Larger sizes of tubing are placed at top, with diameters diminishing toward bottom of hole. It would probably work just as well with larger tubing at bottom, and wells flowing up the casing, but in such deep holes it is impossible to handle the tubing in this manner, on account of the great weight of the tubing suspended in the well."

"Carter Oil Company, with 90 producing wells, has 15 wells flowing through tapered tubing, averaging 118 bbl. each. It also has 15 wells pumping, with average production of 58 bbl. per well. On gas lift it has 52 wells, averaging 733 bbl. each, not including those with tapered tubing. In addition, it has 8 wells flowing natural, with average production of 1,040 bbl. These figures are for the entire district. It is interesting to note that the tapered tubing wells are averaging twice as much as the pumping wells."

"Another company had a well flowing about 141 bbl. on gas lift, using 2½-in. straight tubing in 6⅝-in. casing, and requiring 700,000 cu. ft. of gas per day at 120 lb. working pressure. The straight tubing was pulled, and four sizes were installed, as follows: 378 ft. of 2-in.; 1,000 ft. of 2½-in.; 1,322 ft. of 3-in.; and 1,300 ft. of 4-in. upset. With this hook-up, the well is making 130 bbl. daily on 260,000 cu. ft. of gas. Its 'kick-off' pressure was 230 lb. and working pressure is now 100 lb. It went dead when volume was reduced to 200,000 cu. ft. The operators were planning to use still another size of tubing by setting 160 ft. of 5³⁄₁₆-in. casing on top."

"This well is operating a reduction in gas volume of 63 per cent, accompanied by a loss in oil production of only 8 per cent. Using the 3-ct. figure as the cost of compressing gas, operating costs on this well have been reduced from 14.9 cts. a barrel at 700,000 cu. ft. to 6 cts. a barrel at 260,000 cu. ft. and only one compressor is necessary to flow it. This, of course, does not take into consideration cost of the tubing and labor in pulling the old string and running the new, and no account is taken of production lost while this work was in progress."

"One of the best pumping leases in the field is the Franks property of T. B. Slick, in 35-9-6. This lease has five wells pumping 1,308 bbl. daily, and average of 261.6 bbl per well. The best well is pumping 319 bbl. a day and the smallest 222 bbl. There is one well still on gas lift on this farm, producing 345 bbl. daily at last reports."

Some examples of gas lifts as given by Shaw[1] in various fields will be of interest in indicating the importance that this method has assumed in the production of oil:

"A summary of wells on gas lift in the Seminole field as of Feb. 15, 1927 has been given as follows:

Number wells	Average barrels per well per day	Total barrels per day
87	1,765	153,587

"On Mar. 13, 1927, the production of the Carter Company alone, from air and gas lifts in the Seminole field was as follows:

Number wells	Average barrels per well per day	Total barrels per day
22	2,265	49,840

"It might be noted that gas- and air-lift production in Seminole and in the Los Angeles basin accounts for nearly 10 per cent of all of the oil produced in the United States."

"General data on the operations of air and gas lifts in various fields is given in Table XLII."

Important data in connection with operating gas lifts in California, given in a paper written by R. P. McLaughlin[2] for the A.I.M.M.E. Petroleum Division meeting at Tusla, October, 1926, are noted in Table XLIII.

"As a matter of comparison, data on two Mid-Continent wells are given in Table XLIV."

A very interesting synopsis and summary of the gas lift used in conjunction with repressuring in the Seal Beach field was given by Wm. E. Green[3] and the following subject matter is extracted from his article:

"As a result of the repressuring of partially depleted sands now being conducted by the Marland Oil Company in the Seal Beach field in California, under the immediate direction of

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[1] SHAW, S. F., Principles of the Air and Gas Lift, *Oil and Gas Jour.*, p. 386, June 16, 1927.

[2] MCLAUGHLIN, R. P., Discussion on the Use of the Gas Lift, *Petroleum Development and Technology*, p. 109, 1926.

[3] GREEN, W. E., Gas Lift with Repressuring Effective at Seal Beach, *Nat. Petroleum News*, p. 67, Dec. 21, 1927.

A. H. Bell, production engineer for that company, a number of important conclusions have been reached concerning this method to improve production."

TABLE XLII

	Evangeline, La.	Evangeline, La.	Baku, Russia	Currie, Tex.	Currie, Tex.	Kern River, Calif.	West Columbia, Tex.	West Columbia, Tex.
	1	2	3	4	5	6	7	8
Lift, feet..........	1,135.5	895	770	256	624	407	550	485
Submergence, feet......	377.5	597	694	1,244	876	330	749	1,095
Total length, feet......	1,513	1,492	1,464	1,500	1,500	800	1,299	1,580
Percentage submergence	26	40	47.4	82.9	58.4	41.2	57.6	69.3
Depth of well, feet.....	1,805	1,900	.....	2,900	2,900	.....	3,000	3,000
Diameter casing, inches	6	6	4	6⅝	6⅝	.....	.....	.....
Diameter flow pipe, inches..............	4	4	4	6⅝	6⅝	3	4	4½
Diameter air pipe, inches	....	1¼	2½	2½	2½	1¼	2	2
Gallons fluid per minute..................	22	45.2	46.9	119.5	81.4	93	73	102
Weight fluid per gallon	8.7	8.72						
Pounds pressure at inlet	249	259	312	540	380	143	325	475
Total cubic feet air.....	573.5	326	150	......	......	140	246	240
Cubic feet air per gallon	17.92	7.21	3.2	2.0	3.06	1.5	3.37	2.33
Cubic feet required at 100 per cent..........	2.061	1.207	0.99	0.277	0.766	0.788	0.69	0.526
Percentage pumping efficiency..............	11.5	16.8	32.3	13.8	25.0	52.5	20.5	23.9

"The experiment started Sept. 8, when gas was first started into Marland's Bixby 3. Later, Bixby 3 was restored to production and the gas started into Bixby 5 and 6, located more favorably with reference to other Marland wells. The gas repressuring experiment not only resulted in increasing production at a number of Marland wells but at the same time increased production for the Standard and the Associated Oil Company on adjoining leases."

"It has been concluded that the gas lift can be used to greater advantage in connection with repressuring and that the gas lift will reduce the gas-oil ratio if applied early in the life of the well. Another conclusion is that the repressuring system is entirely practical only when all companies interested join hands, or where the company has acreage large enough to operate without reference to offsets. In the case under discussion, the Marland experiment has proved beyond doubt that repressuring

TABLE XLIII.—WORKING DATA AND OPERATING RESULTS AT EIGHT CALIFORNIA WELLS IN VARIOUS FIELDS

Daily production, barrels												
Well number	Age of well, months	Initial	Before gas lift	After gas lift	Depth, feet	Formation exposed (perforated) feet	Diameter casing (oil string), inches	Diameter tubing, inches	Depth to gas inlet, feet	Footpiece (yes or no)	Gas down through casing or tubing	Starting pressure, pounds
1	18	1,040	400	955	4,939	980	6¼	2½	3,790	Yes	C	540
2	19	6,000	296	610	4,638	186	4¾	2½	4,357	Yes	C	360
3	36	3,000	300	380	4,231	235	4½	3	3,368	No	C	
4	30	800	220	420	3,880	62	6¼	2½	3,500	No	C	
5	21	1,375	215	350	4,182	380	6¼	2½	4,142	No	T	310
6	5	250	150	200	4,790	1,387	6¼	3	3,917	No	C	400
7	49	2,800	260	350	3,510	857	6¼	2½	3,125	Yes	C	500
8	38	3,000	500	550	5,251	2,050	5 3/16	2½	3,524	Yes	C	550

Well number	Working pressure	Viscosity of oil,[1] (seconds)	Gas in, 1,000 cu. ft.	Gas out, 1,000 cu. ft.	Water, percentage	Gravity of oil, Baumé	Total gas per barrel of oil, cubic feet	Lift (working), feet	Submergence, feet	Ratio of lift to submergence
1	400	89	. . .	426	2	28	445	2,690	1,100	2.45
2	310	44	. . .	274	2	35	433	3,501	856	2.47
3	120	. . .	239	639	0.2	32	1,680	3,024	344	8.73
4	155	62	749	839	12.0	29	2,000	3,056	444	6.88
5	130	58	750	1,300	0.1	30	3,720	3,768	374	9.94
6	100	80	500	750	0.1	27	3,750	3,631	286	12.7
7	250	120	300	650	1.0	25	1,860	2,401	715	3.36
8	300	120	250	400	0.2	25	727	2,666	858	3.07

[1] Saybolt, 100° F.

TABLE XLIV

Well number	Period	Oil per day, barrels	Pressure gage, pounds	Gas per barrel oil			Volume gas at 100 per cent efficiency, cubic feet	Efficiency, percentage
				From compressors, cubic feet	From sands, cubic feet	Total cubic feet		
1	May 19 to 28	1,433	250	261	939	1,200	154.67	12.9
1	May 29 to June 7	1,619	250	345	853	1,198	160.14	13.4
1	June 8 to 17	2,128	250	261	699	915	156.95	17.2
1	June 18 to 24	2,497	250	222	667	889	160.14	18.0
2	July 1 to 10	404	250	606	438	1,044	149.48	14.3
2	July 11 to 17	829	250	745	663	1,408	160.40	12.8
2	July 18 to 24	1,891	250	520	473	993	184.63	18.6
2	July 25 to 30	1,994	250	445	377	823	176.44	21.4

of sands brings worthwhile returns to the company, and at the same time benefits the wells on offset acreage."

"The experiment has indicated it is better to drive the oil up structure than down structure. Also under this method there would not be the need for as many inside wells as under the old practice. The experiments have indicated to a number of engineers that the total ultimate recovery on a lease will be greater under the repressuring method than under former methods of producing wells."

"Another interesting fact developed is that gas can be pumped into a well under a pressure as high as 1,850 lb. without danger, as this was done on the Marland lease for a 5-min. period. This extreme high pressure was not needed, however, as it later developed that a pressure of about 1,500 lb. was sufficient for the peak load, when the fluid in the hole was being pushed out of the hole and in starting the flow of gas into the formation. A pressure around 1,400 lb. is now being used."

"Recently it became necessary to stop pumping gas into one of the Marland wells for a few days, and within two days, production started to decline in nearby wells. Repressuring started again at the second well and it was expected that production of the adjoining wells would return to normal."

"The repressuring method indicated that trapped oil that might never be produced could be secured. Recently it was found that some of this trapped oil between Marland's Bixby 5 and Standard's San Gabriel 2 was coming out under the push of the gas as it penetrated the formation, thus securing oil that probably would have always been lost unless a new well was drilled at the right point."

"It has also been found that, under the combined gas-lift and repressuring method, the gravity of the oil is not changed sufficiently to make any change in the price of the product. Also the natural gasoline content of the gas, after being used once was found to have about the same content as when first run through a natural gasoline plant."

"The first plan for repressuring was to pick a centrally located well, with the expectation that the oil production up structure would be increased and that the water which had encroached up to the center of the lease would be driven back toward the edge wells on the opposite side of the lease. Upon application, it was found there was a very rapid increase in production of the wells up structure but no appreciable change in either the water content or production of the wells down structure, which were producing, both before and after the test, fluid which contained about 90 per cent emulsion."

"This basis for arriving at the pressure required for the repressuring work was by taking the static fluid level in the well where the gas was to be introduced and calculating the pressure exerted by this column of fluid at the top of the sand. The Bixby sand receives its pressure from a water drive and the fluid stood very high in the wells. When the gas was actually introduced into the sand it was found to check out within 50 lb. of the previously estimated requirement. As there was very little precedent to work on in selecting a machine of large capacity to work at 1,500 lb. pressure, the design of special high-pressure cylinders to meet requirements was left to the C. and G. Cooper Company. The actual pressure required to start the gas into the sand amounted to 1,500 lb,. which later dropped to 1,400 lb. Volumes average about 800,000 cu. ft. per well per day."

"It seems to be a common impression that the cost of compressing gas to such high pressures is excessive, but, when considered on a basis of compression ratios, it will be seen that the work in compressing gas from 600 to 1,500 lb. is actually less than that required to compress it from 30 to 600 lb. Consequently, the one 170 hp., 1,500-lb. compressor will almost handle the output of three of the same size engines at 600 lb. The discharge from this machine is taken out of the end of the cylinder through forged steel elbows and the two lines taken outside the building where they join together and are carried under ground until they are a safe distance away from the plant. The measurement of the gas is handled on the suction of the machine rather than the discharge in order to use lower pressure equipment. All extra heavy high-pressure pipe and high-pressure steel fittings are used and the connections into the head of the well are made with as few fittings as possible, for safety, with a check valve at the well head to prevent backing up of the gas in the event of a shutdown at the plant. It was found advisable to put a blowoff connection from the well head to the sump, as the well will usually flow when the pressure is relieved and small bleeders suitable for gas would not handle the flow of oil."

"The tubing is carried down very close of the top to the sand and set with a wall packer and the space above the packer filled with water to prevent any pressure coming on the casing in the upper part of the hole. The head is closed in tight. Due to the extremely high pressures and temperatures of the gas it is necessary to provide adequate expansion provisions where a very long line is used and high-grade separators are necessary on the intake lines to prevent condensation troubles in the cylinders."

"Two compressor plants were built, one in the Bixby lease and one on the McGrath and Selover lease. Both plants are identical in design, except that the Bixby plant contains one high-pressure machine for repressuring work and four regular machines for gas-lift work. The McGrath and Selover plant contains five machines for gas-lift work. Due to poor soil conditions, ten 35-ft. piles were driven for each compressor foundation and all compressor blocks tied together with two 18 by 24 in. concrete beams. The building and cooling tower foundations are supported on piles and are entirely independent from the compressor foundations. All trench walls and floors are separated from the compressor building."

"The compressors are 170 hp. twin Coopers. The high-pressure machine is a Cooper of a similar rating, with twin 4½ by 20 single-acting, high-pressure cylinders, which boost the gas from 600 to 1,500 lb. The auxiliaries consist of Worthington centrifugal pumps, motor driven, with a gasoline engine driven stand-by and an Ingersoll-Rand motor driven booster compressor to boost the gas from 600 to 1,000 lb. for starting gas-lift wells, and a Worthington single-stage vertical motor driven air compressor for starting air at 200 lb."

"The control room, which is partitioned off in the same building, contains two headers, one for the 600-lb. gas and one for the 1,000-lb. booster gas, which are manifolded together and controlled with Vogt needle valves. Westcott gas meters with Robinson orifice fittings are placed on each of the 2-in. lines which leave the manifold and run to the wells. The cooling tower is a Fluor sectional tower, using Griscom-Russel 'bentube' sections for both the jacket water and gas cooling. All lines are carried in underground trenches, there being no overhead piping whatever in the plant."

"The wells are equipped with a 4-in. high pressure master valve above the head and a 3 by 4-in. cross with a welded wye above. One side of the cross is closed off and the other side leads with a gate valve and fittings to the sump for blowing off the well and for emergency purposes. On the straight run above the wye is a gate valve opened only when swabbing the well and the branch of the wye leads directly up to the trap set in the derrick. This arrangement is for the purpose of eliminating frictional resistance to the flow of the well. Various types of injection footpieces, perforated tubing, and plain tubing were used with no difference noted in the results. This arrangement worked very satisfactorily for all wells except those which contained a high water content, in which case the emulsion seriously hampered the operation of the trap and the dehydration equipment."

"During August, the average conditions per barrel of oil on four Bixby sand wells and one Selover sand well, were as follows:

Gas input, 1,000 cubic feet	Gross production	Wet gas, 1,000 cubic feet	Gravity	Percentage cut	Gas-oil ratio, cubic feet, barrel		
					Input	Sand	Total
467	714	634	18.9	46.35	790	264	1,054

"This method has recently been supplanted by a fluid displacement pump which is run on a packer and functions by the fluid valve lifting and cutting off the entrance of the gas while the fluid is rising in the tubing, and the fluid valve closing again when the fluid has reached approximately its static level, and in so closing, opening the gas valve, allowing the gas to force the oil from the tubing, after which oil enters again. It was found that the time interval of these flows is from 3 to 5 min., depending on the depth of the tubing and that the flow intervals are exceptionally regular. This pump has served three purposes, namely, to increase production by eliminating the gas pressure acting on the fluid in the hole, thereby reducing the back pressure on the sand; to eliminate bad emulsions by preventing mixture of the gas and fluid, and to lower the total oil-gas ratio."

"The averages per barrel of oil for October on twelve wells were as follows:

Gas input, 1,000 cubic feet	Gross production	Wet gas, 1,000 cubic feet	Gravity	Percentage cut	Casing gas-oil ratio, cubic feet, barrel			
					Pressure	Input	Sand	Total
340	953	557	19.3	40.1	42.9	357	228	585

"Two of the wells in this group were equipped with the National automatic pumps which materially helped to lower the oil and gas ratio. This group contains one well which had an input ratio of 2,374 cu. ft. per barrel, otherwise the average ratio would have been even lower than the figures indicated."

"Experience of the Marland Company was that the tubing depths cannot be varied at will as would seem to be indicated in many of the recent articles on gas-lift work, but that each well has a certain depth at which uniform results may be obtained. If the well is tubed deeper a heading will occur, causing a loss of production during the time pressures are building up to blow off the head, and if the well is not tubed deep enough it will have a tendency to blow through, lowering the gas efficiency. It has been found that many of the wells have different fluid levels or fluid pressures at different times of the day, these pressures raising and lowering at seemingly regular intervals for which no explanation has as yet been found. The percentages of water content also vary during different periods of the day in a similar manner and no doubt have a direct bearing on the change in pressures."

"After carefully studying the results of the gas lift and repressuring work on the Marland wells in the Seal Beach field in California and in wells on adjacent properties, the following conclusions regarding this method of oil recovery have been reached by their engineers:

1. The gas lift using plain tubing gives considerable trouble in wells making water, which offsets most of its advantages.
2. Trouble from gas pressure holding back pressure and from emulsions can be greatly reduced by the use of some device similar to automatic fluid displacement pumps.
3. The gas lift in general is most effective when used in conjunction with repressuring, which artificially raises the fluid levels in the wells.
4. The gas lift, when applied early in the life of the wells, will greatly reduce the oil and gas ratio, thus conserving gas for the work of moving oil into the well rather than expending it in lifting oil to the surface.
5. Repressuring is entirely practical even where very high pressures are required, provided the size of the property is sufficient and the location on the structure is such as to allow the recovery of the oil on the same property where the repressuring is done. The rate of production can be increased thereby reducing costs per barrel and the ultimate economic recovery can be increased.
6. Full cooperation of all producers in a field is necessary for the maximum benefits to be derived from repressuring work.

7. Indications are that, on large properties, repressuring can be used as a means of driving the oil up structure to the line wells, eliminating drilling the usual number of inside wells. Even though total recovery per acre might not be as great by this method, the earnings in dollars would be greater, due to greatly reduced drilling costs. However, it will be necessary to locate wells with this program in mind before it will be possible to prove the theory. The location of the wells for the repressuring at Seal Beach was dependent on the use of wells which were small producers and were not located to the best advantage for repressuring. Even with this handicap the repressuring has shown excellent results in conjunction with the gas lift."

The following items were taken from one of the technical journals as showing that conditions in some of the older fields are favorable for the air-gas lift application:

"The air-gas lift, by reason of its success in the Seminole area, has not had as much attention paid it in connection with its application to older producing areas as some recent trials would seem to merit. Two operators, the Barnsdall Oil Company and the Phillips Petroleum Company, with production in the Dutcher sand at Bristow have applied the lift with gratifying results. Quite recently, the Barnsdall Company applied the air to its No. 2 Hattie Vaughn in the SE NE SW SW of 33-16N 9E, a well which had not been making any oil due to the fact that it had been impossible to keep the water pumped off. While this well is still in the experimental stage it has been making about 20 bbl. a day on air as against nothing on the pump."

"The cost of installing the compressors and other equipment was about $6,000, of which $1,000 was cash outlay for labor and trucking from Seminole, where the equipment had been in use. The remainder was a paper charge, for this material had, of course, paid for itself in Seminole, but the charge of 60 per cent of the new value of the equipment installed was made against the well. It will be of interest to see if it can be made to pay out a second time, carrying an operating cost of about $20 a day."

"Much the same experiment was begun by the Phillips Petroleum Company about 8 months ago in a well two locations south and one location east of the Barnsdall well. This well had been making less than 20 bbl. of oil a day. Since the time the air lift was applied it has averaged 72 bbl. a day, an increase of nearly 250 per cent."

"All wells in this area have been cutting the oil to such an extent that treating plants are installed on most leases. The air lift has not increased the treating cost per barrel, so that the increased production is having a fair chance to prove that air lift may be used in many places where it had not previously been tried."

Brad Mills[1] published an article on the effects of the gas lift in regard to production, at Santa Fe Springs, of the Union Oil Company's properties. The following subject matter is extracted from that article:

"Before dealing with the Union's success, a few words concerning the discovery, the remarkable rise, and the sudden decline of the Santa Fe Springs field will probably help the reader to understand why it was necessary to seek a remedy for a situation which threatened to make the operation of many leases unprofitable."

"The first producing well was drilled by the Union Oil Company in 1919, but as it was located on the flank of the structure and so deep that it failed to attract much attention, it is not generally regarded as the discovery well. Production was less than 200 bbl. and even the major operators were skeptical as to the value of such a small production at so great a depth. The oil sand was found around 4,500 ft.—a depth considered a little impractical in 1919. In November, 1921, the Union Oil Company completed Bell No. 1 as a 5,000-bbl. producer. It is sometimes regarded as the real discovery well of the field."

"At the height of production, the Union Oil Company alone was responsible for nearly 60,000 bbl. a day output. The whole petroleum world was thrown out of balance. There was a concerted effort to shut in some of the production from the field. The Union Oil Company did partially shut in some of its wells. The result was a production of around 45,000 bbl. for the company. After the lid was lifted, the Union's wells did not again produce up to the old peak. The intensive drilling campaign had done its damage. The gas pressure was weakening and production tumbled at a furious rate."

"Every operator in the field was in the same boat. They all watched their production decline a little more each month. One by one, the wells ceased flowing, and many were too deep to be pumped economically."

"Early in 1925, the Union Oil Company began to experiment with various gas-lift installations. Its production had declined from 60,000 to 4,700 bbl. Some of the producers that had been the pride of the company were ceasing to flow, and something had to be done. It certainly could not be much worse than it was. There seemed to be a good quantity of gas left in the sand, even though it was insufficient to make the wells flow on their own initiative."

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[1] Mills, Brad, Gas-lift Increases Production at Santa Fe Springs, *Oil Weekly*, p. 78, Dec. 2, 1927.

"The company had some old compressors of uncertain age and stamina, and they were promptly assembled at Santa Fe Springs for the experiment. They were put to work but were not entirely satisfactory. It was found later that they were far too small and were asked to do more than could possibly be expected of them. However they did more good than harm."

"The next step was to move an old steam compressor to the field for further experiments. Soon after it was put to work, results were very satisfactory. The steam compressor could deliver almost 2,000,000 cu. ft. of gas, and it was found that if it was not overloaded, it increased production materially."

"Bell No. 12, originally a very good well, was flowing only 150 bbl. when the old steam compressor was hooked on early in 1925. Production jumped to 600 bbl. almost immediately. The company has experimented with the well until it is now producing 850 bbl. Such results were not to be denied."

"There are three principal producing sands in the Santa Fe Springs field. The first is found near 3,500 ft., the second at 3,650 ft., and the third at 4,250 ft. The lowest sand is comparatively thick, many of the wells having been completed below 4,700 ft. Crude from the first sand is 26 gravity, that from the second about 31.5, while the lower sand yields 35 gravity oil. The Union has applied the gas lift to all three sands and has been successful in almost every instance in each formation."

"It was first thought that a high gas pressure and a small quantity of gas would produce the wells best. Laboring under that impression, the company was handicapped in its first experiments. Some wells responded fairly well to the treatment, enough so at least, that the company did not become discouraged with its first ventures."

"After a series of tests, it was found that a moderate pressure and a larger volume of gas flowed the wells more satisfactorily than the opposite. In this way, the flow was more uniform, the fluid level more constant and the tubing pressure considerably less than when the high pressure was employed."

"The gas-lift hook-up in the Santa Fe Springs field is one of the simplest on record. While it might not work at all in some regions, it does its work splendidly there. It consists simply of a string of tubing inside the string of casing, which is set on the oil sand. The gas is released in the top of the casing, immediately below the casing head, exerting a downward pressure on and mixing with the oil, forcing it up through the tubing. In many cases two or three wells have been installed on the flow line between the casing head and the trap. It was stated that the tubing pressure is higher in such a case than it otherwise would be. The company is now installing flow lines in as near a straight line as possible. Where it is necessary to make turns in the flow line, it has been found far better to make them as 'easy' as possible. By simply bending the flow line gradually or by installing 45-deg. ells, this may be accomplished. The slightest addition of friction has resulted in a greatly increased tubing pressure."

"Although the simple hook-up just described is in general use, it has been found that by allowing the gas to enter the well through the tubing and forcing it out through the casing, some good results have resulted for a short time. Flowing the wells through the casing has been satisfactory only when the wells had been allowed to stand for some time and the fluid level had become very high. The company has always reversed the flow of gas after the fluid level was brought down to the proper point. When the fluid level is very high, it has been found a very difficult matter to start the wells flowing by merely releasing the gas in the top of the casing in the usual way. An enormous pressure is necessary to start it flowing. By reversing the gas flow, as noted above, the trouble is overcome."

"Wells have been put on the gas-lift system in the various stages of production. Experiments in the field have shown that the best time to place a well on gas lift is just before it stops flowing, or as soon after as possible. There is still a buoyant effect and all the well needs is a little assistance, it has been found. It was also found that wells in a semiflowing state did not produce satisfactorily on the pump. The frothy, foamy state existing in the well was a distinct handicap."

"A careful check is kept on the amount of gas used in flowing each well. A meter is placed on the lead line to the well and one is also installed on the gas line leading from the well. It is rather an expensive process to keep a record in such a way, but the company has found that it is the most satisfactory arrangement. In this way, each well is studied, as a separate unit in the system, and by gaging the production against the net gain or loss of gas, it has been possible to determine the proper volume and pressure required to obtain the greatest amount of oil."

"It has been found that the largest amount of input gas does not always produce the greatest amount of oil. In some cases, the reverse is true, however. Each well presents a separate problem and the quantity of gas required varies accordingly. The quantity of gas used in each well varies from 200,000 to 800,000 cu. ft. daily, depending upon the individual 'pep' displayed."

"Just as the largest amount of gas does not always produce the most oil, an exceedingly high pressure is not generally effective. The pressures applied in the different wells vary from 80 to 250 lb. The condition of the well determines the pressure required just as it does the volume."

"The rock pressure in each well has much to do with both the volume and pressure required. It has been found that if the rock pressure is much smaller than the pressure required to flow the well, there is the possibility of a loss of gas in the operation. The sand will actually absorb more of the gas than the well can give up. The condition is far from general, however."

"The company particularly watches the net gas-oil ratio of the lease, as well as of each producer. In other words, every effort is made to produce each barrel of oil with as little gas as possible—either that put in the well or that naturally coming up with the oil. A barrel of oil can absorb only a certain amount of gas without expansion. Producing an excess of gas with the oil also rapidly depletes the natural gas supply in the sand, making the tendency of the oil to remain in the ground all the greater. As the gas is gradually depleted each well becomes a more stubborn producer."

"The Union has found that by shifting the tubing to different levels in the hole, the most economical point of suspension may be found. By placing the tubing as low as possible, much gas is saved. But by placing it too low, maximum production is impossible, even though a little gas is saved. An extremely low level also requires much more pressure to lift the oil as the fluid level is so far removed from the mouth of the tubing. The best level has been a point where a moderate pressure was required and where the fluid level was high enough from the mouth of the tubing to prevent an easy breaking through of the gas. Shifting the tubing downward from this ideal position increases the pressure and saves some gas while raising it reduces the pressure and shows an excess of gas."

"There are now 17 wells on the gas-lift system in the field. They require an enormous quantity of gas daily. Yet, the daily gain in gas for the lease is more than 4,000,000 ft. The gas saved from that used through the lead lines, plus the natural production from the wells is very satisfactory."

"In the course of its operations, one two-stage, 16 by 9½ by 24 Worthington steam compressor which is sufficient for four wells has been installed. It will deliver about 2,000,000 cu. ft. daily under ordinary conditions. A battery of six 80-hp. boilers has also been installed. The company has found its own equipment useful in many instances, particularly in experimentation. It was the old steam compressor that originally proved the gas lift a practical way to produce oil in the Santa Fe Springs field, and it still has its place."

"Practically every well on the lease is controlled through one manifold house. It is possible to flow each well with a different pressure, or a series of wells may be flowed with the same pressure. A small compressor has been installed to build up high pressure, when necessary to start wells or to lower the fluid level. This high pressure may be sent to any well through the elaborate series of valves."

"Through the application of the gas-lift system in the field, production has been raised from considerably less than 5,000 to 7,200 bbl., with only half the wells on the system. Practically every well has shown a good increase with the new method, and officials stated that the entire installation as a unit had been entirely satisfactory."

Summary.—An oil well ceases flowing when the volume and pressure of the gas in the sand are no longer sufficient to offset the weight of the column of oil in the tubing. When this state is reached in any field or well, the producing company must resort then to either mechanical means, pumping or swabbing, for the recovery of further oil, or the deficiency in gas pressure and volume must be offset by the introduction of more gas or air under pressure. Such a statement may appear to sum up the problem of increased recovery in simple language and in a simple manner, but during the last few years of research and development along these lines many experimenters and investigators have found that the problem is not solvable, as a rule, by the mere introduction of more gas to replace the gas previously removed or recovered under its own pressure.

The increased recovery of oil and natural gas, such gas usually bearing increased amounts of recoverable gasoline, by air- and gas-lift methods as a means of securing successful artificial flowing of oil wells has been attended by much success throughout various fields in this country and, at the same time, it is known that numerous attempts to secure results in this line of work have been of negative value. This often occurs in fields or pools where successful methods are employed on neighboring leases. Yet sufficient success has been attained to point to the absolute practicability of the procedure and much development is under way in many fields of the United States, and especially in California.

In the practice of installing successful gas-lift systems it has been found that much consideration must be given to the characteristics of a given field, to the type of oils and gas undergoing development, and to the conditions as to sand and water, inasmuch as the proper proportioning and balancing of all details differentiates between success and failure.

Some authorities have been quoted as saying that gas-lift principles are applicable only to shallow fields and that the artificial flowing of extremely deep wells could hardly be attended with success using present equipment and information at hand. The successful operation of gas-lift installations in California has entirely discounted this early statement. Along these lines it may be well to call attention to the world's deepest producing oil well—the E. J. Miley 6—producing from a depth of 7,591 ft. at Athens, Calif. Fifteen hundred pounds pressure was required to start the well flowing, which decreased to ten hundred pounds after the flow was started.

Still further articles stated that oil wells yielding under 500 bbl. daily were hardly fit subjects for reclamation installations, and this, too, has not proved exactly correct. The installation of gas-lift units in the Torrance field where wells were formerly yielding 50 bbl. daily and under, has resulted in highly profitable ventures, for several Torrance wells are yielding many times their previous number of barrels daily, along with an increase in the gasoline content of the gas upon its return to the absorption plant.

There is, however, no cut and dried or arbitrary rule or method for the installation of gas-lift systems in any field or for any individual well. Each well is an individual problem and must be handled with the utmost regard for its peculiarities.

There are several systems of gas-lift procedures employed on the West coast, which are, naturally, more or less similar in mechanical items, but which differ in theory on some points and in the results secured. The equipment employed as a rule is comparatively simple, consisting, usually, of compressor units, lead lines, control head, tubing, and return lines. Other items of equipment are often employed concerning which little information is available either because of the patent status or the policy of the company. This applies to various types of mixers, pressure and volume regulating control valves, etc. Types of equipment, however, are not at present of the utmost interest, whereas results secured are of certain value and importance, for proof of any gas-lift system is found only in the production charts of the wells before and after the installation of the system. Since gas and its pressure determine the flow of oil, however, it is quite evident that where the gas is controlled with accuracy in volume, temperature, velocity, and mixture with the oil, the proper flow of oil from the well is obtained.

"Using the gas-oil ratio data for pumping and gas-lift wells during the past year in southern California," Mr. McCollom says, "there is afforded a direct comparison showing the estimated percentage recovery by these methods, and also the expected increase of recoverable oil from the original oil in the formation that would not have been recovered by the pumping method."

"On the basis of this production, it is found that 23 per cent of the total oil in the sands was recoverable by the pumping method and 33 per cent by the gas-lift method, a net gain of 10 per cent of the total recoverable amount of oil, or an increase of 43 per cent over the original calculated ultimate production of the pumping well. An analysis of these data suggests that by the use of the gas lift we have accomplished two prime purposes, first, a saving in the number of feet of gas per barrel of oil lifted, and, second, a conservation of gas in the sand to help activate the oil remaining in the formation."

Unquestionably, the air lift will have a marked influence on the peak production of each new pool, its rate of decline thereafter and the relation between flush and settled production, says J. O. Lewis,[1] of the Dunn-Lewis Oil Recovery Company, Tulsa; but Mr. Lewis believes that the use of the air lift will prove to be inseparably involved with casing-head gasoline production, the application of pressure to the sands and with cooperative development of oil pools in distinction from competitive operations:

"I do not think we will have to reconstruct our entire ideas as to the ultimate recovery from oil pools on account of the gas lift. The chief benefit from the gas lift in increasing production has been in the Seminole and Wewoka pools, where the gas-oil ratio is less than 500 cu. ft. per barrel, and where the wells either do not flow when they are drilled in or else have an exceedingly short flowing life."

"On this type of production the gas lift is of tremendous importance and will show up in the decline curve just as though the wells had not stopped flowing. In other words, the decline curve of Seminole will have all the appearance of a normal gas-oil ratio curve and will eventually have to break to the pumping production of the field; but that break will be extended over a very much longer period than without the use of the gas lift. It is certain in these fields that the air lift will recover the oil much faster than without its application and I believe it will recover several thousand barrels more to the acre. This is because in rapid recovery, under the conditions prevailing at Seminole, the gas has less opportunity to dissipate its energy, and the oil is produced with a volume of gas not greatly in excess of that dissolved in it, thus not robbing an appreciable amount of gas from other oil in the sand."

"The success of the gas lift at various wells has upset some theories as to rate of decline of production. It has not yet been determined what rule or theory will serve in wells which are susceptible to the use of the gas lift."

"The gas-lift method of flowing oil wells is not recommended as a cure for all production problems where it is used. It, however, does make possible:

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[1] Lewis, J. O., Information appearing in a compilation by Paul Wagner, *Nat. Petroleum News*, p. 86, Mar. 16, 1927.

1. The lowering of lifting cost.
2. Increasing the ultimate yield.
3. Decreasing the time of obtaining the ultimate yield.
4. The retardation of bottom water encroachment.
5. The operation of deep wells where the cost of swabbing or pumping is prohibitive.
6. Reduction of rig repair due to swabbing.
7. The reduction of cleanout jobs and loss of producing time.
8. Elimination of pumping repair jobs.
9. Reduction of lease labor.
10. Protection of wells by keeping them on steady production.
11. The recovery of gasoline in excess of the amount recoverable by other means.
12. The conserving of gas in the formation which is the most important factor in ultimate production."

"The future of the air and gas lift, as the writer sees it, is particularly in handling deep wells where rods give trouble; in handling wells making sand, or that should make sand to clear the sand pores of detritus to secure free flow to the well; in handling production where the daily quantity is too small and the depth too great for economical and profitable operation with working barrels."

"And the future depends upon technical skill of design and operation. It has been demonstrated that with efficient design of air-gas lift, the production of wells can be increased much beyond that obtained with the former type of air-lift employed; also that small wells can be operated by air lift with tapered tubing at a cost that places this method in competition with beam pumps in many fields. The next step in conservation that the writer expects to have an opportunity to demonstrate is that of restoring the pressure in a pool and producing by air-gas lift all of the oil possible to lift economically. This combined operation is probably the method toward which we shall eventually be working in recovering the maximum quantity of oil from pools where the oil is recovered through bore holes."

"In view of the newness of the method in the minds of many operators, it will necessarily run the gamut of all the speculation out of which much interesting comment is to arise. It should rest reasonably settled that the method can do no hurt to the normal oil reservoir; that it extends the flush life of production; that it sustains wholly or partially the initial resident pressure of gas in the rock, etc. But the matters about which the individual will be concerned run to other details of consideration, and going beyond the data of the mechanical technology involved, there arises for very interesting and serious consideration the other data in which the operation of the individual lease has to assume its own consequences. It would appear, for the moment, that stratigraphy and the condition of the structure with reference to varying porosity, position of the water lines, and position of individual leases in the structure gradient are of vital importance, as related to individual leases or divisions of operation. It is probable that the data which may govern the disposition of these matters will be a long time wanting. In fact, with reference to porosity, it would seem at present improbable that any lease owner may be able to determine to his own satisfaction what his own lease condition may be, or ever to know definitely whether the application of one flow pressure all over the pool area may be fair and impartial to himself or with regard to this particular incident. As to the lines of water encroachment on an edge lease in a pool, it may or may not be possible to develop data of experience which is useful to the operator for his surmises. As a matter of rough and ready conclusions, it would appear that the application of maximum pressure in his own case for the flowing of his own wells might tend to retard the encroachment and serve to such an edge-lease owner a reasonable share of protection. So far as this writer's present information goes, the matter of stratigraphic position with regard to gradient or drainage in the sands is one very important, and should be known as thoroughly as possible to each lease owner."

"Naturally one jumps to the conclusion that in the general application of pressure-flow methods to a pool, the lease resting on the dome would have to use extreme care as the life of operation is developed, and particularly would this be true in case the pitch of the structure is steep, and where the drainage would naturally be away from the crest. The applicant of pressure to flow the wells in the crest, it would appear, might suffer seriously if he became too aggressive in his extent, both in volume and pressure, of activity. Out of regard for this latter phase of operation no doubt the largest consideration has arisen in the minds of experts looking to the consolidation of pressure application. Even so, the leases on the upgrade portion of the strata might have to have scientific consideration with reference to application of some differential of pressure in their favor."

An article by S. F. Shaw[1] is here quoted as published:

"In view of the rapid progress being made in the improvement of petroleum production through the use of engineering methods, it does not seem amiss to discuss what appears to be the probable method toward which we are tending."

"We will first assume a new field, penetrated by only one drill hole, and the well producing 1,000 bbl. or more per day with gas pressure similar to such fields as Tonkawa, Seminole, Huntington Beach, or Ventura."

"Control of this first well will be maintained, beginning with the initial stage, either by choke or air-lift tubing of careful design, to reduce the quantity of gas as closely as possible to that absorbed in the oil actually lifted; in most fields when first opened there is several times as much gas dissolved in the oil as is required to move it through the sands and to lift it to the surface."

"The fluid will be delivered to separators from which the oil will gravitate to the receiving tanks and the gas will go to a gasoline plant, as soon as one is built, for the removal of the gasoline content. New wells will be drilled from time to time and the production will be handled as for the first well."

"In the course of time, the removal of oil and gas will result in diminishing the pressure of the gas in the pool. Careful record will be kept to show the rate of decline of pressure, and as soon as this pressure has declined to a point at which there is less gas dissolved in the oil lifted than is required to move it through the sand and bring it to the surface, compressed gas will be admitted to the well to assist the gas lift, which has to this time been operating as a natural gas lift, but from now on will operate as a combination of natural and artificial gas lift."

"The handling of the oil and gas so produced will continue as previously, but from this point it becomes of the greatest importance to strive for the highest air-lift efficiency possible to reach, otherwise gas will be consumed in excessive quantities. There is much improvement to be sought, as indicated by the low lifting efficiencies prevailing where 5 to 10 or 15 per cent is now the rule, instead of 25 to 50 per cent which is attainable."

"During operations so far there has been no attempt to restore any of the gas to the sand, the only gas reused being that employed as aid to the gas lift; but a point will be reached, which will be determined by test and experience, where part of the gas can be restored to the sand through certain selected wells, which will thereafter be employed only for this purpose. It is desirable to restore gas to the sand as early as possible since a maintenance of high pressure will serve the following purposes:

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[1] Shaw, S. F., Natural and Artificial Gas Lift Will Be Combined in Future, *Nat. Petroleum News*, p. 97, Apr. 6, 1927.

1. There can be maintained a high differential pressure between the sand and the well, thereby providing the means of moving the oil through the sand and at the same time permitting a pressure to be maintained at the well sufficient to enable a gas lift to operate successfully.
2. Viscosity of the oil will be held at a low point, thereby enabling the oil to be moved through the sand with minimum loss of pressure.
3. Absorption of the gas in the oil will be more effective and the pore spaces will, in consequence, become more readily filled with the fluid, thereby reducing the tendency toward by-passing, or channeling.
4. Encroachment of edge water will be delayed to maximum extent."

"When the state of operation is reached that the gas has established a complete cycle through the sand to the well; then to the surface with the oil; through the compressor plant; and back to the sand; the path of the gas will be first through the separators to the low-pressure cylinder of the compressor, thence to the condenser coils or to the absorption tower to extract the gasoline, then to the high-pressure cylinder, and then distributed, partly to the sand for maintaining the pressure, and partly to the gas lift."

"With this completely closed cycle, the decline in production should ultimately approximate that of almost complete exhaustion of the oil in the sand. Who can say what then will be the degree of recovery reached? Only actual performance will determine this point, but instead of 15 to 25 per cent accepted as the probable average percentage recovered at present it would not seem improbable to expect a recovery of 75 to 90 per cent, and conservation will then have reached a high degree of efficiency."

"Nearly all of the steps mentioned above have been started, though most of them have not reached a perfected stage. A large number of air and gas lifts are now in operation but the efficiencies obtained as a rule are very low. In order to carry the above cycle to the final stage of practical exhaustion of the sand, it will probably become necessary to operate these gas lifts with low submergence, owing to the comparatively low pressures that will prevail, particularly in the later life of the field."

"Owing to inefficient designs, operations with low gas-lift submergence is attended with such low efficiency at the present time as to render gas lifts impracticable at this stage, and yet it is possible to obtain acceptable efficiency with low submergence, as has been proved by the writer in unwatering mines, and it is expected that in the near future the writer will have the opportunity of demonstrating that low submergence can also be employed efficiently in oil-well operations."

"The steps involving compressing the gas to any desired pressure, and of extracting the gasoline either by compression or absorption methods have been worked out quite satisfactorily. Flooding the sand with compressed gas under low and medium pressure has been successfully carried out, but the use of high pressures, 400 lb. or higher is in the experimental stage."

Summarizing, it can be stated that problems involved and associated with the process are so numerous that new data and improvements will continue to be forthcoming. It has been definitely proved that for some wells, though not for all, the gas-lift process increases the daily production of oil and gas over and above the amount that could be procured by present pumping methods. The process has not been used long enough yet to furnish sufficient data to prove whether the ultimate production of an oil pool will be increased or the supply of oil merely secured at an earlier date on account of the application of the gas lift process. There are many factors that enter into this problem and the industry will have to wait for the final answer. At the present time, at least it can be safely said that the gas lift results in bringing the oil and gas to the surface quicker and more cheaply than if it were produced by pumping methods. This may or may not be a conservation of the oil and gas deposits.

Conclusions as stated by Bennett[1] are:

"1. Where pressure conditions are suitable for using the gas lift the flow rate of wells thus producing can generally be increased over the rate which can be maintained by other means."

"2. When the gas lift is used to increase the daily rate of a well, instead of being used as a means of back-pressure control, the ultimate production of a well will generally be decreased."

"3. If the gas lift is used as a means of controlling the pressure on the formation the daily rate will be decreased but the well's ultimate production will be increased."

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[1] Bennett, E. O., Effect of the Gas Lift on the Gas Factor and on Ultimate Production, *Petroleum Development and Technology*, p. 158, 1927.

"4. The gas lift is effective in increasing the ultimate production of the field under hydrostatic pressure where water has encroached into the oil-bearing formation."

"5. Where offset wells are producing on the gas lift, the best results and greatest ultimate recovery can be made when they are operated under similar conditions. An agreement as to pressure and rates should be reached by the operators. Trying to beat the offset generally works to the disadvantage of each."

"6. To obtain the greatest ultimate yield from a well, complete knowledge of pressures and volumes must be obtained. Proper equipment and supervision is the only way in which this can be done."

CHAPTER XVIII

PARTICULAR INSTALLATIONS OF THE AIR OR GAS LIFT

Some Analyzed Installations by Shaw[1]

An article by Shaw gives a number of analyzed examples of the air or gas lift installations which are extracted on the following pages:

"Example 1 is that of well No. 32 of the Crowley Oil and Mineral Company, at Evangeline, La. The efficiency of 11.5 per cent is very low; but a low efficiency is to be expected in a lift of 1,135.5 ft. where a 4-in. pipe is employed."

"Example 2 is that of a well, also at Evangeline, owned by the Mamou Power Company. In this case, again, the efficiency is low for the same reason as in Example 1."

"Example 3 is that of a well situated in the Baku field, Russia. The efficiency is fairly satisfactory for the usual arrangement of air-lift installations at oil wells. A more efficient arrangement under the prevailing conditions would, however, reach an efficiency of 65 per cent."

"Examples 4 and 5 are those of a well at Currie, Tex. The fluid contains a very large percentage of water. Installation arrangements are inefficient."

"Example 6 is that of a well in the Kern River field, Calif. The efficiency is surprisingly high. An efficiency of 60 per cent is about the highest possible figure that could have been reached with the most efficient type of installation."

"Examples 7 and 8 are those of two wells in the West Columbia Field, Tex. The efficiencies are a little better than the general run of oil-well installations, but leave considerable to be desired. Maximum efficiencies obtainable would range between 65 and 70 per cent for the conditions at those two wells."

"In Example 9, the quantity of water pumped was at the rate of 30,800 bbl. per day, but at one time about 40,000 bbl. per

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[1] Shaw, S. F., Principles of the Air and Gas Lift," *Oil and Gas Jour.*, p. 388, June 16, 1927.

Table XLV.—Data on Various Oil Wells Where Air Lifts Have Been Installed

	No. 1	No. 2	No. 3	No. 4	No. 5	No. 6	No. 7	No. 8
Lift, feet	1,135.3	895	770	256	624	470	550	485
Submergence, feet	377.5	597	694	1,244	876	330	749	1,095
Total length, feet	1,513	1,492	1,464	1,500	1,500	800	1,299	1,580
Submergence, percentage	26	40	47.4	82.9	58.4	41.2	57.6	69.3
Depth of well, feet	1,805	1,900	....	2,900	2,900	....	3,000	3,000
Diameter casing, inches	6	6	4	6.625	6.625	....	....	....
Diamter flow pipe, inches	4	4	4	6.625	6.625	3	4	4.5
Diameter air pipe, inches	....	1.25	2.5	2.5	2.5	1.25	2	2
Fluid per minute, gallons	32	45.2	46.9	119.5	81.4	93	73	102
Weight fluid per gallon, pounds	8.7	8.72	....	....	....	....	....	....
Pressure at inlet, pounds	249	259	312	540	380	143	325	475
Total air, cubic feet	573.5	326	150	....	....	140	246	240
Air per gallon, cubic feet	17.92	7.21	3.2	2	3.06	1.5	3.37	2.33
Air at 100 per cent efficiency, cubic feet	2.06	1.207	0.99	0.277	0.766	0.788	0.69	0.562
Pumping efficiency, percentage	11.5	16.8	32.3	13.8	25	52.5	20.5	23.9

Data on Air Lifts Where Low Submergences Were Employed in Tests Made by *Shaw*

	No. 9	No. 10	No. 11	No. 12	No. 13
Lift, feet	548	1,070.2	846	1,097	1,176
Submergence, feet	230	20	214	225	176
Total length, feet	778	1,090.2	1,060	1,322	1,352
Submergence, percentage	29.5	1.9	19.9	17	13.2
Water per minute, gallons	900	67	425	236	159
Pressure at inlet, pounds	100	9	93	98	77
Water per day, barrels	30,300	2,297	14,570	8,090	5,450
Air per gallon, cubic feet	....	29.68	4.47	6.84	12.42
Pumping efficiency, percentage	....	....	57.8	31	21.6
Air at 100 per cent efficiency, cubic feet	0.96	....	1.69	2.12	2.68

day were being pumped. In fact, there would have been no difficulty in handling 100,000 bbl. of water per day with this air lift, after certain changes in the installation had been made."

"In Example 10, the pumping of 2,300 bbl. per day against a head of 1,070 ft. and with a submergence of only 20 ft., or a pressure of 9 lb., was an unusual performance."

"Examples 11, 12, and 13 give the results of other tests in which the working conditions were different from those of the first two examples."

"Air lifts have been employed in oil wells at Currie, Goose Creek, Hull, Humble, Luling, Mexia, Mirando City, Powell, and West Columbia, in Texas; at Caddo and Evangeline in Louisiana; at Kern River, Long Beach, Sante Fe Springs, Salt Lake, Rosecrans, and Torrance, in California; at Smackover, Ark.; and at Blackwell, Kay County, Okla. For this service, the usual make of compressor to be found in the Texas oil fields is the Ingersoll-Rand, two-stage, type X, either belted or steam driven. When driven by oil engines, the fuel cost is very low. The data applying to these compressors are as follows:

Nominal size, cubic feet	Size of air cylinder, inches	Stroke, inches	Revolutions per minute	Displacement, cubic feet	Power required at 350 lb. pressure
300	12 by 5½	14	170	308	95
500	15 by 6¾	16	150	491	152

The Tonkawa Field, Okla.

"The Tonkawa deep sand area in Oklahoma offered a very good opportunity for trying out the air-gas lift. Getting the oil from the wells after they had stopped flowing was found to be a costly and troublesome proposition. The chief method of production was swabbing. This was found to be both expensive and annoying. The necessity of maintaining a crew of a cleanout driller and a helper, and using a boiler to furnish the steam required to pull the swab was found to average $60 per day. This amount alone, without any allowances for lease overhead and supervision eliminated the practice from wells of small yield. The other obstacle in swabbing the wells was unfavorable weather conditions. During the rainy or snowy seasons, the wells were not swabbed regularly. The irregular operation caused a loss of production which greatly reduced the profits."

"When the deep sand wells in this field were pumped, much difficulty was experienced with working barrels and cups. The barrels sanded up, and the cups found the work of handling the fluid very difficult. From figures obtained on deep pumping wells in this field, an average operating time of 9 days was found before it became necessary to pull the tubing and rods, or at least the rods, and change the cups. This meant that the average yield per well could be measured only by the monthly production; for the wells would produce for 9 days, and then 1 day would be lost in pulling."

"These factors in operating the deep wells at Tonkawa led to the introduction of the air-gas system. Although the principles are simple, the installation is quite complicated, and the best results have been obtained when men thoroughly familiar with these details have been engaged in equipping the wells. There are dozens of variations in 'hooking up' the wells, and they are based upon the varying conditions encountered. In considering this method of producing, it might be said, that each single well must be treated individually, and no set practice nor single pressure can be promulgated for general adoption."

"The type of equipment necessary is a compressor and an engine. The air or gas is compressed, and sent to the bottom of the well and liberated into the producing sand. Its force causes the oil to enter the bottom of the tubing, and flow to the top of the hole. When gas is used, it has been found advantageous to dovetail two branches of the oil companies, the production and natural gasoline departments. When a natural gasoline plant is adjacent to the leases, the residue or tail gas from the plant may be used, and in employing this gas, a double advantage is found. The residue gas in several instances had a gasoline content of 0.2 gallon per 1,000 ft. After this being sent to the bottom of the hole, and being mixed with the oil during its passage through a section of the sand and thence to the separators and back to the gasoline plant, it was found to contain 1.5 gallon gasoline per 1,000 ft. In the instances considered (and they cover several installations), the oil production was increased, and the recovery of gasoline produced was also increased. It must be remembered that the same gas may be recycled over and over again."

"The process is still in the experimental stage, as less than 8 months have elapsed since the first unit was installed in

Oklahoma; consequently a very limited amount of information is available. The past 3 months have witnessed the greatest activity in making installations, and today in Oklahoma and Kansas about 190 wells are being flowed by this method. Treated rather skeptically at first, the system is meeting with success. One lease in the Tonkawa Field was increased from a daily production of 7,000 to 12,000 bbl. by the installation of 19 units. In the Garber field, production of one lease was increased 4,000 bbl. by equipping 10 wells. At the Wewoka deep sand field, the production of one lease was maintained at a figure of 5,200 bbl., while the adjoining lease which was being pumped produced only 1,100 bbl."

"The air-gas machinery is housed in a structure similar to the buildings which house natural gasoline plants. The battery of gages and recording instruments necessary for the intelligent operation of these machines is usually placed in a section of the building. One company has unified control by an engineer who does nothing else but observe the actions on the charts as they record the production of the wells and the pressure applied. He is quick to detect each variation of fluid lifted, and applies the necessary increase or decrease in pressure to the well. This is probably the first instance where wells are 'pumped' from a structure of this character, and it might be termed an application of 'boiler-housing.' Regardless of the peculiarities of operation, the results of the process seem to warrant its extension."

THE PANUCO FIELD, MEXICO

Not alone in the fields of California and the Mid-Continent has the utilization of gas pressure in recovering oil been successful. Those districts have received the most publicity on this subject because the work has been carried out on larger scale. A notable instance of the revival of wells that ceased to flow their production is the work that is being done by the Pan-American interests in the old Panuco heavy oil district of Mexico.

In this field it has long been the custom to abandon any well that ceased to flow. The oil is heavy—averaging 13.7 A.P.I. gravity with viscosity at 100° F. of 6,000 sec. (Saybolt Universal). No present known pumping equipment would handle the oil to advantage.

Not much gas pressure was present, but by taking advantage of what there was, through tubing the wells, the Pan-American has restored several wells to good production. The several wells that have been worked over by tubing were standing full of oil. In one case, where the 10-in. hole was brimful of oil, a mere reduction to 8-in. was sufficient to start the well to flowing 5,000 bbl. daily.

Practice generally on the wells that have been revived was to equip them originally with 8- or 10-in. oil string. The Pan-American in reequipping them runs 4-in. tubing, sometimes with packer, if suitable packer seat can be found, otherwise without packer. Generally, the wells in this district have 500 to 1,000 ft. of open hole.

As the "dead" wells had no derricks, these having been moved away with completion of the well, the Pan-American is making use of a Star machine of the type that is fitted with caterpillar tractor and is gasoline engine operated.

Another method of bringing back the Panuco wells was started by the Pan-American. The wells had been flowed into central tanks a mile or more away. Now, by setting new tanks close to the well, pressure is utilized more effectively.

The Strawn-Ranger District of Texas

The production in the Strawn-Ranger district of Texas is low and in some of the fields has reached the almost unprofitable point. Some of the wells produce as little as 0.2 bbl. per day. In the particular area under discussion, the output range is from 0.2 to 1.3 bbl. per well per day.

In order that the work which was contemplated might be undertaken under the most favorable conditions, the plans were drawn up only after the well logs, production curves, water records, sand correlations, and mechanical problems had been thoroughly studied. All possible well histories were compiled; each well was studied in detail, both as a unit and in relation to the other wells. Much subsurface information was also compiled to give knowledge on the general area. In all, 102 producing wells, about 40 bbl. a day production, and 34 non-producers were studied.

The plans to increase production on this property as worked out by the engineers provide for flowing the wells by heads. In the ordinary methods of flowing wells, after the head has been discharged, atmospheric pressure is permitted to reestablish itself at the bottom of the well. Under the proposed plan, this will not happen; when the contents of a well have been ejected, atmospheric pressure will not be allowed to reestablish itself. The pipe carrying compressed ejecting gas and the discharge pipe will be sealed at the bottom of the well by a ball or other form of check valve.

It is proposed to use an ejection period of 3 min. per hour initially, and in this manner use compressed gas for periodic ejection only 5 per cent of the time. Thus, all the contents, or as much of the contents as prove to give best results, will be removed twenty-four times daily. The ejection period will be lengthened or shortened to meet the peculiar requirements of any particular well or group of wells, in order to effect the maximum efficiency of extraction. This, of course, may mean a variation in the number of times a well will be flowed.

After each period of ejection, the space occupied by the oil and water, or both which were in the well, will become a void to be filled by oil, gas, or water, or all three of them from the producing horizon. Thus the flowing to the well bore of the contents of the sand should be activated and increased production result. According to the engineer who has done the research work, the periodic ejection theory should reduce the total consumption of gas and subject the oil to a minimum amount of spraying, thereby cutting down the proportionate amount of emulsification.

In cases where wells make considerable amounts of water along with the oil, a slight vacuum is produced at the bottom of the hole during the period of ejection, and immediately thereafter the inflow takes place from the sand. It is thought that this automatically keeps the well cavity cleaner, and free from sand, clay, etc.

The ejector will be placed at the extreme bottom of the well cavity, and since there are no working parts other than the ball valve to wear out, the presence of floating sand or other abrasive material will not be the menace it is with the regular equipment for pumping. The simplicity of introducing an ejector immediately above the ball valve, according to the engineer, recommends itself, both in ease of construction and low costs. The attachment by means of which inflowing compressed gas may be introduced is also simple and economical.

Compressed air or gas is supplied to the ejector periodically by means of a clock-controlled, electrically operated mechanism which will, at regular periods, open a valve in the compressed gas line leading to the well. This valve will be maintained in an open position as long as desired and then automatically closed at the end of the ejection period.

Due to the loose sand present, a special design of sand trap was developed and installed. The trap, as its name implies, is a device for catching the sand and preventing its falling back and clogging the screen. The main body of the trap consists of a shell of 3-in. pipe, 15 ft. long. At the lower end of this shell is a swage nipple with a closed collar. Below the swage nipple is the strainer with a plug and anchor. The upper end of the shell connects with a 3 ft. section of 3-in. pipe. This pipe has a swage nipple at its upper end and connects to the plunger barrel. Running through the entire trap shell and extending down into the strainer and about half way through the 3-ft. section of the upper part of the trap is a ¾-in. pipe. This pipe is equipped with a valve at its upper end and is set through the closed collar on the lower swage nipple. Oil enters through this ¾-in. pipe and is admitted to the trap through the valve at the upper end. The feature of the trap is that the valve on the upper end of the ¾-in. pipe be close to the standing valve in the plunger barrel. If the distance between these two valves be much greater than 1½ ft., the efficiency of the trap is lowered.

As the sand enters the trap through the valve on the ¾-in. pipe, it falls back and is caught in the 15-ft. shell. With the average well in the territory where these traps are in use, several months are required to fill the shell, where, without the trap, the screen often becomes closed within a very short time. When the trap becomes filled it can be pulled out and emptied in the same length of time required to pull a well.

Smith-Dunn Process in Southeastern Ohio

In southeastern Ohio, the Smith-Dunn process is extensively applied; in fact the drive idea is used with the air lift to produce wells yielding a fraction of a barrel of oil a day. The air lift is, in this application, used only intermittently.

As described in the *National Petroleum News:*[1]

"The automatic type of air lift besides using more air than does the newer type, which is a hand-operated installation, is somewhat more expensive to maintain. It involved the use of a barrel at the bottom of the well equipped with float connected with valves at the surface. The float rises as the oil does and at a certain level 'kicks' on the air which, acting on the displacement principle, flows the oil to surface tanks."

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[1] Smith, L. E., Some Small Properties of Southeastern Ohio Almost Operate Themselves, *Nat. Petroleum News*, p. 21, June 30, 1926; p. 60, July 7, 1926.

"The newer type depends upon hand-operated valves at the surface. Air is applied to the bottom of the well, usually between the casing and the tubing, and the oil is flowed through the tubing. A salient principle of this type is the setting of flow collars between joints of tubing at the bottom of the well. These are merely tubing collars with a small orifice. 'Pistons' of air enter the tubing through the orifices, boosting the column of fluid in the tubing. The casing head is fitted with vent line, to blow off the air after the well has been flowed, gas and oil lines with valves, and a valve on the air line. With the vent valve closed, the pumper shuts off the gas line, turns on the air, and all the fluid in the well is flowed into the tank."

"Sometimes, where the sand is so loose that the pressure would be dissipated in the formation instead of lifting the fluid, a chamber is set at bottom. Openings in this are small and when it is desired to flow the well, the pressure will be held in the chamber, compelling it to exert its force on the chamber's liquid contents."

SOME MID-CONTINENT FIELDS

General.—The following data is from a paper by S. F. Shaw[1] which was presented at the October, 1926, meeting at Tulsa of the Petroleum Division of the A.I.M.M.E. The detailed work was carried out at Braman, Garber, and Tonkawa in Oklahoma, and at Oxford in Kansas. Following some of his suggestions, a well was also equipped by the Roxana Company at Smackover by A. S. Field.

"The results as a whole in a number of Mid-Continent fields were quite satisfactory in so far as it was possible to carry out these ideas in a limited time. A total of 14 wells produced 6,590 bbl. before installation of the air lift and 13,847 bbl. afterward, thus giving an increase of 110 per cent. The range of increase was from 5 to about 400 per cent where conditions were favorable for the use of the air lift, indicating that in many cases wells would yield a greater production of oil if the fluid were removed as rapidly as it enters the well. Most of this increase was made on wells already provided with the usual type of gas lift."

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[1] SHAW, S. F., Use of the Gas Lift in the Mid-continent Field, *Petroleum Development and Technology*, p. 99, 1926.

"In bringing about this change in operating conditions, it was arranged to remove all back pressure wherever possible. All pockets where air or gas could accumulate and all horizontal flows were eliminated in the flow line, the gas trap being moved close to the well and placed at such an elevation that a gravity line would carry the liquid from the trap to the receiving tank. The flow column or eductor is of such design at the lower end as will reduce to a minimum the slippage loss that usually takes place in the lower section of the eductor pipe, and in the upper section is so designed as to reduce the friction loss in that part to an acceptable minimum." (See Fig. 156.)

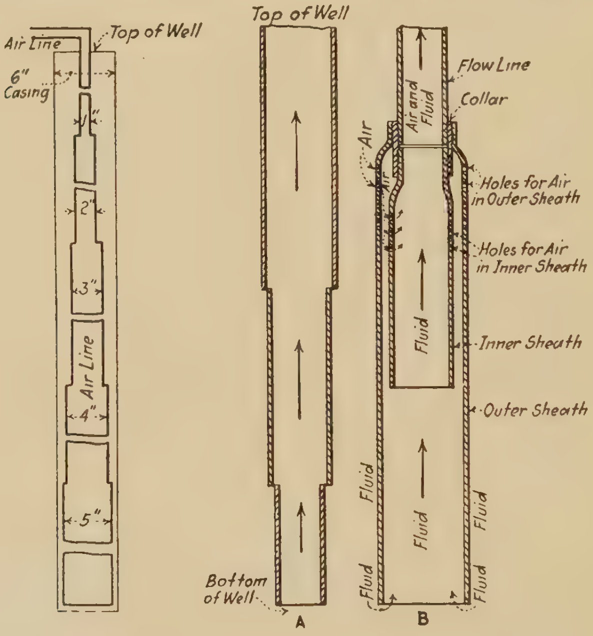
Air Line
Top of Well
6" Casing
1"
2"
3"
Air Line
4"
5"
Top of Well
Bottom of Well
A
Flow Line
Collar
Air and Fluid
Air
Holes for Air in Outer Sheath
Holes for Air in Inner Sheath
Fluid
Inner Sheath
Outer Sheath
Fluid
Fluid
Fluid
Fluid
Fluid
B

Fig. 156.—Diagram showing the method of obtaining increased areas of flow pipe by increasing diameter of air line toward lower end. (Allowance must be made for varying conditions in any given well.) Sketches of flow line, *A*, and slow-flow device, *B*. (*Shaw.*)

"Finally, and not the least important, the wells are operated at the rate that gives the highest acceptable efficiency for the particular set of conditions involved."

"**Method of Calculating.**—Let it be assumed that in a well 3,000 ft. deep, when producing 2,000 bbl. of oil a day of 35° Bé. (0.85 sp. gr.) the liquid column stands high enough to give a pressure of 300 lb. at the lower end of the casing. A liquid column of 35° Bé. would represent 691 ft. of water, or 691 ÷ 0.85 = 810 ft. of oil. The lift would then be 3,000 less 810, or 2,190 ft."

"The losses in lifting oil by air lift include: (1) entrance losses at the lower end of eductor, or flow pipe, that depend on the character of the footpiece; (2) slippage losses of air (or gas) through the liquid, that depend on the design of the flow pipe; (3) friction losses of air along the inside surface of the flow pipe that depend on the design of the flow pipe; (4) discharge losses of air at the outlet that depend on the design of the discharge pipe and of the headpiece, or trap; and (5) other losses of unknown character that are unimportant compared with those named."

"Let us suppose that the conditions in the well have permitted a design that involved the following losses: entrance losses, 5 per cent; slippage losses, 15 per cent; friction losses 40 per cent; discharge losses, 10 per cent; or total losses, 70 per cent. The efficiency that can be obtained when the lift is operating at 2,000 bbl. per day is then 30 per cent. At less than 2,000 bbl. per day, the losses will be changed and the efficiency correspondingly altered."

"The isothermal expansion of air is practically the same as that of a perfect gas, and the quantity of the air at sea level required to lift 1 gal. of water is found by the following formula:

$$Q = \frac{8.55 \times L}{144 \times 14.7 \times \log_e \dfrac{P_2}{14.7}}$$

where Q = number of cubic feet of air to raise 1 gal. to height L; L = feet of lift; and P_2 = absolute pressure in pounds per square inch at lower end of eductor."

"For the conditions assumed in the problem first stated, L = 2,190 ft. and $P_2 = 300 + 14.7 = 314.7$ lb. per square inch. Then

$$Q = \frac{8.35 \times 2{,}190}{144 \times 14.7 \times \log_e \dfrac{314.7}{14.7}} = 2.815 \text{ cu. ft.}$$

which is the quantity of compressed air required to lift 1 gal. of water at sea level under pressure of 300 lb. when there are no losses."

"In the case assumed, the efficiency is 30 per cent and the quantity of air required is 2.815 ÷ 0.30 or 9.383 cu. ft. for 1 gal. of water. For oil of 0.85 sp. gr. the quantity required is 9.383 × 0.85, or 7.977 cu. ft. per gallon; 1 bbl. would require 7.977 × 42, or 385 cu. ft."

"Let it be assumed that the gas has an analysis that requires 375 cu. ft. to lift 1 bbl. of 35° oil and that the gas from the sand amounts to 500,000 cu. ft. per day when lifting 2,000 bbl. of oil. The total quantity of gas required per day is 375 × 2,000 or 750,000 cu. ft. Deducting the 500,000 cu. ft. that is being furnished by the sand, leaves 250,000 cu. ft. per day that must be furnished by the compressor. If the volumetric efficiency of the compressor is 80 per cent when compressing to 300 lb. per square inch, the displacement capacity of the compressor must be 250,000 ÷ 0.80 or 312,500 cu. ft. per day, or 217 cu. ft. per minute."

"**Data on Control of Gas Accompanying the Oil.**—Orifice meters were placed on both the gas input line and the gas discharge line of some of the wells in order to determine the quantities of gas consumed per barrel of oil during the operation. The readings on the input meter chart are fairly satisfactory, but in some cases where the discharge is fluctuating to any extent, the oscillations of the differential pressure needle are rather severe and the readings are not as accurate as could have been desired, this condition making for some apparent discrepancies. However, the general tendencies afford some valuable information on control of the gas accompanying the oil as will be noted in Table XLVI, which gives data on two of these wells.

"It will be noted that at well No. 1 there was, in general, a decrease in consumption of gas per barrel of oil lifted as the quantity lifted more nearly approached the efficient capacity of the eductor. The gas accompanying the oil from the sand showed a gradual decrease per barrel of oil, dropping from 939 to 667 cu. ft. per barrel and in well No. 2 the quantity of gas was reduced to 377 cu. ft. per barrel. These quantities of 667 and 377 cu. ft. can be still further reduced by closer design to meet the exact conditions. In a paper read before the Federal Oil Conservation Board on Feb. 10 and 11, 1926, James O. Lewis estimated that the quantity of gas accompanying a barrel of oil taken as an average in all classes of wells is about 1,500 ft. G. O. Smith states that at Dominguez field, Calif., the input gas under 260 lb. pressure averages about 1,100 cu. ft. per barrel of oil, which with the 1,200 cu. ft., accompanying the oil makes a total of 2,300 cu. ft. required to lift a barrel of oil to the surface, and this is compared with the natural ratio of 2,850 cu. ft. per barrel for that field."

TABLE XLVI.—GAS-CONTROL DATA ON TWO WELLS IN MID-CONTINENT FIELD

Well number	Period	Oil per day, barrels	Pressure gage, pounds	Gas per barrel oil			Volume gas at 100 per cent efficiency, cubic feet	Efficiency, per centage
				From compressors, cubic feet	From sand, cubic feet	Total, cubic feet		
1	May 19 to 28	1,433	250	261	939	1,200	154.67	12.9
	May 29 to June 7	1,619	250	345	853	1,198	160.14	13.4
	June 8 to 17	2,128	250	216	699	915	156.95	17.2
	June 18 to 24	2,497	250	222	667	889	160.14	18.0
2	July 1 to 10	404	250	606	438	1,044	149.48	14.3
	July 11 to 17	829	250	745	663	1,408	160.40	12.8
	July 18 to 24	1,891	250	520	473	993	184.63	18.6
	July 25 to 30	1,994	250	445	377	822	176.44	21.4

"**The Efficiency Factor.**—The gas-oil ratios afford a good basis for comparison when conditions of submergence, lift, and quantity of fluid are identical; when any of these conditions are varied, the efficiency factor should be employed. The efficiency factor is based on the foot-pounds of work performed in lifting a barrel of liquid to the surface compared with the foot-pounds of energy stored in the gas under the pressure obtaining at the lower end of the tubing. It has been noted that, as the efficiency factor is increased, the quantity of gas taken from the sand per barrel of oil is decreased. It will be noted in Table XLVI that the quantity of gas from the sand in well No. 2 was considerably less than in well No. 1. It is assumed that the character of the sand, porosity, etc., makes for this difference. The quantity of gas that is lacking in the oil to raise it to the surface must, of course, be made up by the compressors, and it is desirable to confine the gas coming from the sand to that dissolved in the oil raised, so far as it is possible to do so, making up the deficiency by the compressors."

"**Use of Back Pressure.**—It is generally supposed that back pressures in a new well result in a lower consumption of gas per barrel of oil, rather than when no attempt at control is made, and in an address before the A.I.M.M.E. in 1925, T. E. Swigart has given some valuable data on the use of back pressures in the Dominguez field, Calif. Let us compare the two wells A and G, noted by Mr. Swigart, which were flowing through a bean under conditions of pressure and lift approximating those for wells No. 1 and 2 in the Mid-Continent field. The figures for these two wells are given in Table XLVII."

TABLE XLVII.—GAS-CONTROL DATA ON TWO WELLS IN DOMINGUEZ FIELD

Well	Production per day, barrels	Gage pressure, pounds	Gas per barrel		Efficiency obtained, percentage	Gas required to lift 1 bbl. at acceptable efficiency, cubic feet
			Consumed, cubic feet	Required at 100 per cent efficiency, cubic feet		
A	392	250	1,775	143.2	8.1	759
G	741	225	2,290	148.2	6.0	823

"The gas-oil ratios in Table XLVII are about as satisfactory as can be obtained when employing back pressures at gage pressures

TABLE XLVIII.—COMPARISON OF OIL-WELL GAS-CONTROL DATA

Well number	Gas per barrel oil, input, cubic feet	Gas per barrel oil from sand, cubic feet	Gas per barrel oil, total, cubic feet	Gas dissolved in oil, cubic feet per barrel	Gas, abstracted from oil not lifted, to lift 1 bbl. oil, cubic feet	Saving over natural ratio of 2,850 cu. ft. per barrel oil, cubic feet	Oil that can be moved to well by gas, saved, barrels
A	.....	1,775	1,775	44	1,731	1,075	0.6
G	.....	2,290	2,290	39	2,251	560	0.25
Dominguez	1,100	1,200	2,300	44	1,156	1,650	1.38
1	222	667	889	44	623	2,183	3.27
2	445	377	822	44	333	2,473	7.42

of 225 and 260 lb., respectively. The quantity of gas dissolved in 1 bbl. of oil under these conditions of pressure is about 44 and 39 cu. ft., respectively; consequently, there must be abstracted from oil not lifted 1,731 cu. ft. of gas for each barrel of oil lifted in well A, and 2,251 cu. ft. in well G. A comparison of these figures with those obtained in wells No. 1 and 2 given before, and with the work now being done at Dominguez Hill as noted by G. O. Smith is found in Table XLVIII."

"**Initiation of Control and Period of Application.**—The proper time to bring application of control over the gas would appear to be at the time the well is first brought in, and this control should be continued until the pressure has declined to a point too low for the gas lift to operate with any acceptable degree of efficiency. The first stages of flowing do not require the introduction of compressed gas since there is usually considerably more gas dissolved in a barrel of oil than is necessary to raise a barrel to the surface. After pressure and volume of gas have declined to a point where too much gas is being drawn from distant parts of the sand, a compressor plant should be placed in service to make up the deficiency."

SUMMARY OF SOME CALIFORNIA FIELDS

"There have been very few attempts made to use the gas lift in the San Joaquin Valley or northern fields of California and up to this time there have been no very satisfactory results obtained in those areas. This may be due to conditions in the productive measures which will require careful design and operation which conditions will eventually be met. Favorable conditions under which the gas lift has proved effective are:

1. A minimum rock pressure of 130 lb. per square inch.
2. Clean oil. Where a well produces a small percentage of free water, the gas lift has a tendency to form an emulsion which, in many cases, requires dehydration.
3. A sufficient volume of oil to maintain a proper submergence during the operation. It is difficult to use a submergence of less than 400 ft. The rock pressure may be obtained by closing the well in and reading the pressure from a gage at the casing head after allowing time for the pressure to build up."

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[1] O'NEILL, F. E., Improved Production Methods in the California Fields, *Petroleum Development and Technology*, p. 77, 1925.

"There are various methods of applying gas to the wells being used in California at this time. Two attempts to flow wells by means of the gas lift on Sec. 32–31–24 in the Buena Vista Hills under the following conditions were not satisfactory:

Well number	Depth, feet	Revolutions per minute	Length stroke, inches	Fluid level	Depth tubed	Production, barrels	Percentage change production, loss
1	3,500	30	32	2,700	3,300	200	
1	3,500	Gas lift	. .	2,700	3,300	150	25
2	3,700	30	32	2,900	3,500	200	
2	3,700	Gas lift	. .	2,900	3,500	150	25

"In the first test on these wells, gas from a compressor was forced into the hole through the 2½- to 6¼-in. packing head without being conducted to the bottom of the tubing. A pressure of 400 lb. was necessary to start the flow and only 150 lb. pressure to maintain same. However, it was possible to maintain a flow by heads only and a steady continuous flow was not obtained. The wells were shut down to change connections. The connections were rearranged and a packer placed on the tubing above the fluid and a port cut into the tubing above the packer. Into this port and leading down through the tubing a gas conductor pipe was welded and equipped at the bottom in such a manner that the gas was discharged through a jet upward into the bottom of the tubing. This packer method is designed to meet conditions of low rock pressure and low fluid levels and is considered unnecessary with high rock pressure and fluid level but in this case, it gave the same results as the previous method and the gas lift was discarded as not suitable to the well conditions. After removing the gas lift the well was put on the beam and pumped at a 200-bbl. rate. This was an increase of 50 bbl. a day over the production secured by the gas lift."

"The surging or head flow may be caused by the footpiece design, use of compressor of insufficient capacity, application of too much gas to the particular well, or other causes."

"Another attempt to use the gas lift in the San Joaquin Valley was made by the Federal Drilling Company on Sec. 20-31-24, Midway field. The well was flowing at a 500-bbl. rate when it quit and the pressure varied from 0 to 150 lb. At that time it was put on the beam with the following results:

Well number	Depth, feet	Revolutions per minute	Length stroke, inches	Gravity, degrees Baumé	Fluid level	Depth, tubed	Production, barrels
1	4,836	30	32	26.6	2,700	4,304	300

"There was 71 ft. of perforated casing in the well. While pumping, the well made 96,000 cu. ft. of gas per day with a gasoline content of 2.06 gal. per 1,000."

"The rods and valves were pulled out of the hole and dry gas from an 8 by 4½ by 8, two-stage compressor was forced in between the 4¾ oil string and the 2½-in. tubing. It required 540 lb. pressure to start the flow and 320 to 400 lb. to maintain same. The well produced for 12 days flowing steadily:

Cubic feet gas put in	Cubic feet wet gas recovered	Gasoline content gallons per 1,000	Production, barrels	Percentage increase
200,000	455,000	1.6	450	50

"While pumping, 198 gal. of gasoline was recovered per day, and while producing from gas lift, 728 gal. of gasoline per day was recovered, which represented an increase of 530 gal. per day. The gas recovered from the well being operated by the gas lift, deducting the amount forced into the well, showed an increase of 159,000 cu. ft. per day over that recovered while pumping and the increase in oil production was 150 bbl. per day. While operating under the gas lift, the total net increase in value of gas, gasoline, and oil was approximately $190 per day."

"The well was shut down in order to remove the pump barrel from the bottom of the tubing and to clean out the hole. Sand was found to have filled the hole 68 ft. This was cleaned out, the pump barrel removed and the well tubed to 4,484 feet or 180 ft. below the previous tubing depth but only a few hours' production was obtained on account of sanding trouble. The tubing was pulled back to its original depth, 4,304 ft., but the sand trouble persisted and the well was put back on the beam under the following conditions:

Well number	Depth, feet	Revolutionsper minute	Length stroke, inches	Gravity, degrees Baumé	Fluid level	Depth tubed	Production, barrels	Percentage decrease
1	4,836	30	32	26.6	2,700	3,921	300	33⅓

"The well produced 108,000 cu. ft. of gas daily, containing 2.16 gal. of gasoline per 1,000 cu. ft. after being put back on the beam. When the well was being flowed through the pump barrel it was flowing through the tapered set in the standing valve barrel which measures about 1⅝ in. inside diameter as against 2½ in. inside diameter with the barrel removed. This decreased diameter at the bottom of the tubing in all probability had a tendency to hold a restraining pressure on the sand enough to prevent sanding up. This back pressure being lost when the pump barrel was removed permitted the sand to run in too rapidly to be handled by the fluid."

"Many tests run on the gas lift in the Santa Fe Springs field by various companies have been successful and have frequently given as much as 100 per cent increase in oil production besides a commercial increase in gasoline extracted. The following furnished by one of the large operating companies gives a comparison between pumping and flowing wells by gas lift in Santa Fe Springs:

THE BELL SAND, ROCK PRESSURE 310 LB.

Well number	Depth, feet	Revolutions per minute	Length stroke, inches	Gravity, degrees Baumé	Fluid level	Tubed	Production, barrels	Percentage pressure increase
1	3,850	26	32	30.5	Low	3,825	380	
1	3,850	Gas lift	..	....	Low	.....	625	64.5

THE MEYER SAND, ROCK PRESSURE 230 LB.

Well number	Depth, feet	Revolutions per minute	Length stroke, inches	Gravity, degrees Baumé	Fluid level	Tubed	Production, barrels	Percentage pressure increase
1	4,650	24	40	33.7	3,700	4,570	175	
1	4,650	Gas lift	..	....	3,700	.....	375	114.3

"A further comparison between pumping wells and flowing by the gas lift in the Dominguez field shows:

Well number	Method	Production, barrels	Percentage increase
1	Pumping	163	
1	Gas lift	315	93.3

"When this well was pumping, the entire lease produced 6,000 gal. of gasoline per day. By putting this well on the gas lift the gasoline production for the lease was raised to 29,000 gal. per day."

"Signal Hill has also shown remarkable increase in oil and gasoline with the gas lift."

"In almost all gas-lift operations the Baumé gravity of the oil is decreased from 0.5 to 1° but this decrease is offset by the increase in gas and gasoline and in many cases the gasoline increase will pay license fees on the patented methods."

"There are a large number of wells which can be operated more profitably by pumping than by the gas lift but there are also many cases which rightly belong to the gas lift and which cannot be operated as profitably by any other method."

Seminole Field, Okla.

An interesting feature in this field is the extremely low gas-oil ratio or gas factor, which is only about 500 cu. ft. of gas per barrel of oil, on the average. Rock pressure of the gas has not been determined, but it is undoubtedly low. Wells making as high as 8,000 bbl. of oil daily will make only from 2,000,000 to 3,000,000 ft. of gas. There is neither a separate gas sand, nor a high pressure gas strata which must be penetrated before getting to the oil sand. What gas exists is in the top of the Wilcox, and is believed to be dissolved gas from the oil rather than a separate body of natural gas. It is very rich in gasoline content, making as high as 4 gal. per 1,000 cu. ft.

The low gas factor indicates that the wells will not flow naturally over a great length of time, and this is leading most companies to provide means of artificial stimulation for use when conditions make it necessary. In general, they plan to use compressed air or gas to lift out the oil as soon as a well starts flowing by heads. It will be the first instance in Oklahoma where general use of air lift is resorted to in a flush field before wells have been allowed to decline so far that their operation by any method becomes unprofitable. It is likely the air lift will be successful in keeping production considerably above what it would have been without its use. A few operations as summarized by one writer were described as follows:

"One company, the Amerada Petroleum Corporation, has been using a gas lift on one of its wells for a month or more. This particular test is still in the experimental stage, and there is little to determine yet as to whether the gas lift has been a help to the well or not. When first applied, it brought about a considerable increase in production, but when the gas was off for a week recently, the well produced as much oil as it had been producing when the gas pressure was on."

"One well is producing about 1,375,000 cu. ft. of gas daily, or about 530 cu. ft. per barrel of oil. This gas is compressed to 500 lb. pressure and introduced into the well through a string of 2-in. tubing. Bottom of tubing is now at about 3,100 ft., or about 1,050 ft. above bottom of hole. Four Chicago Pneumatic Tool Company compressors are forcing this gas down the well, the gas making a continuous circuit from the well, through the compressors, down into the well again, up with the oil, and into the separator. Two of the compressors are being run by electric motors and two by Waukesha gasoline engines. The gas coming from the well is so rich in gasoline that it could not be handled through the high-pressure cylinders of the compressors, and it was necessary to install a small plant to denude the gas before it could be used."

"The gas, after passing through the low-pressure cylinders of the compressors, runs through a simple gasoline plant consisting essentially of two heat exchangers and two accumulator tanks. The denuded gas then returns through the high-pressure cylinders and into the well. This small plant has been making 3,000 to 4,000 gal. of gasoline a day, the gasoline being placed in storage. In this instance, production of gasoline is incidental and is looked upon as more of a nuisance than anything else, as the main idea in stripping the gas is to make it fit to use in the compressors."

The conditions in the Seminole district are summarized by Shaw[1] in his paper which was presented before the Fort Worth meeting of the Petroleum Division A.I.M.M.E.

"The graph in Fig. 157 shows the production curve of No. 2 Grisso well in the Seminole pool, arranged in averages of 10-day periods. This well was one of the early wells of the Carter Oil Company to be placed on the air lift. Up to June 30, this well had produced a total of approximately 585,000 bbl. The production curve shows a drop from the normal between the dates of Feb. 16 and 28, caused by curtailment of production. It will be noted that when the well was again operated at maximum capacity, the curve was restored only to the point at which it would appear to have declined had there been no curtailment, hence there was a loss of production of approximately 20,000 bbl. from this well during that period. The lower end of the production curve tends to flatten, and it is possible that a fairly well-settled production can be expected from this point unless there is an encroachment of water which would cause a rather sudden drop. The input pressure, starting at 410 lb. per square inch has declined as was to be expected. The gas-lift factor has shown

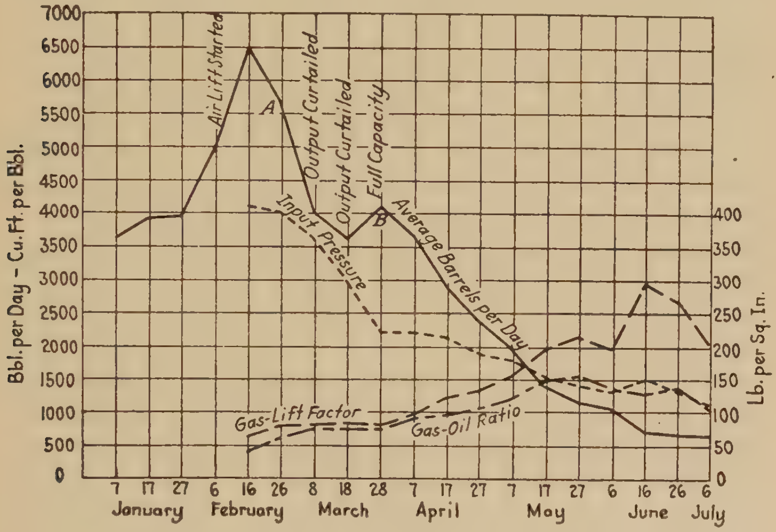

FIG. 157.—Production curve of No. 2 Grisso, Seminole Pool. (*Shaw.*)

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[1] SHAW, S. F., Air-gas-lift Practice in the Seminole Field, *Petroleum Development and Technology* p. 100, 1927.

a rather rapid rise in cubic feet per barrel of output gas from the well toward the last periods noted. The gas-oil ratio, obtained by substracting the input gas per barrel from the output gas per barrel, shows a fairly regular increase to May 27, when it began to decline. It has been noted on some occasions that this decline in the gas-oil ratio indicated the approach of water encroachment. The decline in the gas-oil ratio, must, of course, be made up by input gas in order to maintain the maximum production of oil from the well.”

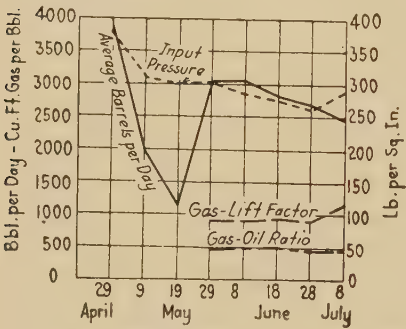

FIG. 158.—Various data for No. 1 Bowlegs, Seminole District. (*Shaw.*)

“Figure 158 contains curves of the various data for [Carter Oil Company] No. 1 Bowlegs, Seminole, Okla. The sudden drop in the early stage of production appeared to be a natural decline; the well was shot, after which the curve rose to the point shown at May 29. The input gas pressure has not declined greatly as yet, and the gas-oil ratio has held at a fairly low point, that is, under 500 cu. ft. per barrel, which is one of the lowest gas-oil ratios at any of the wells of the Carter Oil Company in the Seminole district. The gas-lift factor has been rather low, though on July 8 there appeared to be a tendency toward an upward bend in this curve. A test was run on this well on May 27, and the best operating efficiency was found to be 21 per cent.”

The oil from the Seminole Wilcox sand displays a very limited pressure. This may best be illustrated by the action of a well which had been flowing into a gas trap with a back pressure of 10 oz. The flow line was put directly into a battery of tanks removing the back pressure, and the production of the well increased 3,000 bbl. Another well in a part of the field was flowing 900 bbl. daily, and a string of tubing was lowered into the hole. When the tubing was half way down the hole, the well stopped flowing altogether. The tubing was pulled out and the flow of the well started again. This indicates the great sensitiveness of the production. In another instance, a swab rubber dropped into the hole causing the flow of the well to stop; when the rubber was extracted the flow revived of its own accord.

These actions might be expected of wells flowing 100 or 200 bbl. daily, but it must be recalled that they occurred in wells making a production of four figures daily. In a well in the central group of producers, a string of tools was lowered into the hole for the purpose of cleaning out the hole, and their entry immediately caused the flow to stop.

The fact that a Seminole well does not flow seems to mean little. There is an instance where a well had only 800 ft. of oil in the hole, and failed to flow. It was thought to be a mighty poor producer but a shot of 20 qt. made it flow 1,800 bbl.

There are other problems of operating in this field. It has been proved fatal to introduce air lift into a well which is making any water. The oil possesses a percentage of sulphur and when subjected to the action of air and water this forms sulphuric acid. The acid has, in the case of one well, "eaten" entirely through the string of casing. The air lift in this field is used by sending the air down inside the tubing and flowing the wells between the tubing and the casing. In some cases, the casing is a water string and is run to shut off a hole full of water. Should the acid eat through the casing in any of these wells, the water would be released into the sand, a dangerous condition.

No attempt will be made here to quote from or refer to the large number of articles which have appeared in the technical journals and which have described, some in general terms and some in detail, the installations and practices of the various operators in the Seminole district. The journals publish their yearly indices and anyone interested may find the description from these sources. The progress of the application has been so rapid that a published description may be entirely out of date in 2 or 3 months; it is useless, therefore, to attempt to extract too many of the past articles.

THE CAT CANYON FIELD, SANTA BARBARA, CALIF.

As reported by George Reid:[1]

"The Cat Canyon field is located about 15 miles south of Santa Maria, Santa Barbara County. Its production is classed as heavy asphalt base oil, having a gravity of from 8 to 10° A.P.I., which may be described as thick, black, and sticky, being so viscous that at ordinary atmospheric temperature conditions it will not flow. When pumped from the well, prior to the installation of the gas-lift system, the pumping operation lifted the oil, with much difficulty, to the surface where it was discharged into open ditches conducting the oil down hill to the sump, where steam coils were used to heat it. It is no exaggeration to state that this oil had to be helped down hill to the first heating sump with wooden rakes, etc., especially when the weather was slightly cool, for instead of flowing, the oil seemed to roll over itself in semisolid lumps. Former practice embraced heating the oil by means of submerged steam coils in three or four open pits or sumps, which really were sand traps, for the pumped production usually carried from 15 to 25 per cent of sand in the oil. No water was, or is, present in the production."

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[1] REID, GEORGE, Gas Lift Economical in Handling Heavy Oil, *Oil Weekly*, p. 30, Nov. 12, 1926.

"Production on the R. and G. Oil Company's Cat Canyon lease comes from a depth of around 3,000 ft., and under the rod and pump method of operation three wells produced at the rate of 75 to 125 bbl. each or at the rate of approximately 9,000 bbl. monthly. No separators were employed, for the oil would not flow through a separator, and the small quantity of gas produced was not conserved. Crude oil was consumed under the boilers for the generation of steam, for the gas produced was not sufficient for this purpose, although the small amount of gas yielded was conducted to the boilers and burned rather than wasted in the air. The consumption of crude oil necessary for steam generation ranged from 600 to 1,000 bbl. monthly."

"During the late spring of this year [1926] the Loomis Oil Well Control Company installed their gas-lift system on this lease. The first well entered was R. and G. No. 4, which was placed on the compressor June 7. The results secured by the installation were very gratifying for the production of this particular well was increased from 75 to about 450 bbl., and the gravity raised to about 13° A.P.I. Immediately following this success, the gas-lift system was applied to wells No. 3 and No. 5, with the result that production of crude oil was doubled. Later, well No. 9 was completed and brought in on the Loomis system for about 550 bbl."

"In addition to the increase in production secured in the first three wells entered and put on the compressor is the striking result of the practical elimination of sand in the oil, and where the crude formerly carried from 15 to 25 per cent sand, the production fresh from the well carries less than 1 per cent sand and no water."

"The gas-lift installation consists of the compressor plant and lead lines for gas circulation to the wells, etc., plus the Loomis type control valves, controlling the volume and pressure of the gas at the casing head, for four wells are being flowed from one central compressor plant discharging gas into a single header line for distribution to the wells. The gas pressure regulator control valve at the well, being adjustable, controls the volume and pressure of the gas entering the individual well. In addition to the above, the installation involves the use of the Loomis type flow device, which is placed at a predetermined level, or depth, in the tubing. Both of these items are described in *The Oil Weekly* issue of Sept. 27, 1926 (p. 32)."

"The compressor plant installed to compress the natural gas for flowing the four wells now operating under the flow device consists of two Ingersoll-Rand two-stage compressors, 12 × 6 × 12 in., which are driven by 110 hp. Bessemer gas engines (13½ by 18). The gas enters the low stage at 3 lb. pressure and is increased to 100 lb., after which it is cooled in coils placed in a small water-cooling tower back of the plant. At this point a small amount of gasoline is removed, about 30 gal. daily. The gas then returns to the high stage to be compressed to about 500 lb. discharge pressure. Both compressors discharge into the same 'high' line which serves as a distributor of gas to the various wells, each of which flows under a little different pressure and volume of gas. A Lunkenheimer relief valve is installed on the low-pressure side of each machine and an American relief valve on the high-pressure side of each compressor as a safeguard against accidental fouling of the gas flow."

"The compressors are discharging 600,000 cu. ft. of gas into the wells and the natural gas production of the lease has increased from an amount insufficient to fire the boilers to 1,250,000 cu. ft. This condition eliminates the necessity of using oil under the steam boilers and they are now fired with gas; thus effecting a saving in this one item of $600 to $1,000 per month over the former method of operation."

"Since the crude oil produced under the gas-lift method is much less viscous and will flow with comparative ease and is free from sand, all of the steam heating in the first three pits or sumps has also been eliminated, which effects a marked decrease in steam consumption, showing still further saving in operation costs. The only sump now heated by steam is the fourth, or last, pit where the oil is raised in temperature to 180° F. to assure freedom of movement in the pipe line."

"The gas, at a pressure of approximately 500 lb., is lead to the well in uninsulated lines to pass through the pressure regulator control valve, and then through the preheater, before entering the casing."

"Natural gas under pressure and at 200° F. is injected into each of the four wells. The crude produced leaves the well at about 130° F. and the gas leaving the well is naturally about the same temperature. The temperature of the oil as produced under the pump and rod method was 70 to 80° F. at which temperature the oil tends to become semisolid, and a slightly lower temperature results in an almost 'hard' oil."

"One of the secrets of successful gas-lift installations is the actual conversion of the oil column in the tubing into a column of froth, effecting a great reduction in the weight of the column and making it possible to lift this oil froth at lower pressures. The froth breaks easily with the light oils, but the froth produced at Cat Canyon is more difficult to break. The closed storage will solve this small problem."

"The exchanger, or preheater, employed in heating the gas before it enters the well is 4 ft. long by 10 in. in diameter, using 10-in. casing. Thirty-eight tubes, 3 ft. long, welded into headers, are enclosed in the exchanger shell, the gas passing through the tubes and live steam through the shell. All of the water condensed by the heat interchange is recovered and conducted to the water-cooling tower for use over the compressors."

"The oil is a little unusual in appearance for crude of such type, heavy, asphalt, and viscous. This is because of the contained gas in the oil. When the oil and gas is mixed in the bottom of the hole, the oil dissolves so much gas that it rises to the surface in the form of froth. In the separator the froth is broken down and practically all of the gas is released, just enough remaining in the oil to give it a frothy appearance which tends to give it fluidity and it flows easily. The closed tankage being constructed will be equipped to recover this gas as it leaves the oil, and this rich vapor, along with the production of gas from the entire lease, will be handled through an absorption plant for the extraction of gasoline. Since the installation of the gas lift, the gasoline content of the gas has increased from 2 pt. to 1 gal. per thousand cubic feet."

"During the months that the four wells have been flowing under gas-lift devices, there has been no labor cost nor loss of time. Each well has produced evenly with no surging or violence, without being off production since the gas lift was applied. Upon completion of the closed storage, the series of sumps now employed as tanks will be eliminated. This will also eliminate the present volumetric loss due to evaporation, and in addition will tend to reduce steam consumption used for heating the oil prior to loading."

"The lifting costs at present are just one-third of the former cost of producing the oil, and it is estimated that the installation of the closed tanks, and the careful recovery of all oil, gas, and vapors will reduce the lease operation cost to about one-half of the present scale, or approximately one-sixth of the former expense of operation. It seems highly possible that such excellent results may easily be secured, for production of oil has rapidly increased since the installation of the gas-lift system. The lease was formerly producing about 9,000 bbl. monthly under a very costly method, whereas it is now producing 30,000 bbl. per month, from four wells, with another well due for completion soon, under a highly efficient and much cheaper producing method. Natural-gas production has also shown a remarkable increase."

"On this lease, and in the successful flowing of these various wells, Loomis engineers have found that each attempt to flow each separate well has been a separate engineering problem, and it is stated that each well was successfully handled only after proper study and consideration of any or all of the many contributing factors influencing the experiment."

"The results accomplished by gas-lift engineers at Cat Canyon are of special interest and the success of the venture is attracting lots of attention, for it indicates that inexpensive lifting of heavy oils from relatively low levels can be accomplished with little, if any, more difficulty than encountered in the flowing of the lighter crudes, and that lifting costs can be reduced to the point where heavy, low-priced oils can be produced very profitably, and with no grief."

Marland Installation in the Texas Panhandle Field

The following information is condensed from an article by C. D. Lockwood:[1]

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[1] Lockwood, C. D., Gas Lift Reduces Paraffin Trouble, *Oil and Gas Jour.*, p. 37, Nov. 18, 1925.

"On the strength of results obtained in experiments, the Marland Oil Company has started construction of a 1,200 hp. compressor plant on its Johnson A lease in the south half of the northeast quarter of Sec. 20, Block Y, near Borger and it will probably be ready to start putting gas back into the producing horizon within 30 days. Ten or twelve wells on the Johnson A property and the Whittenburg A lease in the Mary Whitley survey, just north of Sec. 20, are to be produced by gas lift to begin with, according to present plans, which call for enlargement of the plant to care for additional wells as soon as expedient."

"E. O. Bennett, production engineer of the Marland Oil Company, with headquarters at Fort Worth, outlined briefly to the American Mining and Metallurgical Engineers at Tulsa last month his experiments in flowing wells in the Panhandle with preheated gas. The announcement of this new plant which with the necessary power lines will cost in the neighborhood of $75,000 means, probably, a revolutionary change in lifting methods in the Panhandle. Residue gas from the company's gasoline plants will be used and that means additional conservation. This is highly important since the rock pressure in several parts of the Hutchinson County field has declined alarmingly during the past 2 or 3 months. At the beginning of development, the pressure was uniform at approximately 400 to 450 lb. Now it is down to 300 lb. in several parts of the field and lower than that in some places."

"The new compressor equipment consists of six 200-hp. compressors driven by 200-hp., 2,300-volt motors. The capacity is approximately 7,700,000 ft. of gas at 300 lb. discharge pressure. This gas will be discharged from all compressors into a common 'header' and distributed by volume control equipment into the individual wells. Electric power will be used for compressor and other needs, the price rates here being very reasonable."

Foran[1] summarizes conditions in the Panhandle and West Texas areas in a paper presented before the Fort Worth meeting of the Petroleum Division of the A.I.M.M.E. as follows:

"Nearly all of the gas-lift wells in this area are from 2,900 to 3,200 ft. deep. The tubing sizes in the wells vary from 2½ to a maximum of 4½ in., depending upon the size of the well.

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[1] Foran, E. V., Mechanical Installation of the Gas Lift in Texas Outside the Gulf Coast Region, *Petroleum Development and Technology*, p. 59, 1927.

Due to the extremely rapid deposition of paraffin in the flow tubing, it is necessary to clean the tubing daily or every other day by means of a mechanical scraper, the operation of which has been described in detail by Bennett and Sclater."

"Mixed flow strings in the Panhandle area are not used, as they would require a different size scraper for each section of the tubing where a change in the diameter occurs. This to a certain degree limits the efficiency obtainable as the entire 3,000 ft., more or less, of tubing is of the same diameter and, therefore, will have a widely variable ratio of velocity between the bottom and top of the well. For the most efficient operations it would seem that the velocity ratio of the gas-oil mixture throughout the tubing should be kept as nearly constant as possible."

"The position of the bottom of the tubing varies in different wells. In some cases it is kept at 600 ft. above the top of the producing formation, and, in other cases, it is set at a point just above the top of the producing formation. It is believed that if the tubing were set at certain points within these ranges, that maximum efficiency would result."

"The required working input pressures to flow wells in the Panhandle vary from approximately 100 to 225 lb. per square inch. Under these conditions the gross gas-oil ratio varies from 2,200 to 3,500 cu. ft. per barrel of oil. The net gas-oil ratio varies from 200 to 600 cu. ft. per barrel. The starting pressures required on these wells vary from 250 to 500 lb. per square inch."

"The power for compression used in the Panhandle area is both gas engines and electric motors. The gas is separated in the traps and passed through gasoline compression plants and then into the high-pressure stations. In some cases dry gas is compressed to the required pressure and transmitted to the lift wells. The rock pressures in the Panhandle lift wells vary from approximately 175 to 400 lb. per square inch."

Another writer states:

"Gas-lift methods of production in the new fields of West Texas are occupying considerable attention. During the past six months, the air and gas lift has been employed in the Crame-Upton County area by the Humble, Tidal, Gulf, Marland, Simms, Landreth, and other companies. In the Howard County fields some preliminary experiments have been conducted but there are, as yet, no permanent plants. In the Noodle Creek field in Jones

County, the Marland Oil Company has been operating by gas-lift methods during the past 8 months."

"In the McCamey area, both the Marland and Roxana companies have tried to overcome the difficulties encountered in handling the corrosive hydrogen sulphide, but success has been limited and marked by frequent interruptions in the operations of the plants. The production in the McCamey area comes from lime at about 2,100 to 2,300 ft. The tubing used in these wells is 2½ and 3 in. It is usually set 300 or 400 ft. off bottom and the input air pressure at the casing head varies from 160 to 200 lb. Air is used as insufficient gas is available for this purpose. The corrosive action of the air and sulphur gases is so severe that tubing must be replaced in these wells every 6 weeks. This gas cannot be used for the engines as it will completely burn through the piston head in 3 or 4 mo."

"The Church and Fields University pool in Crane County is probably the most active area of gas-lift operations in Texas, at the present time. The production from this area comes from a lime formation from 2,600 to 2,700 ft. in depth. One of the outstanding features of the operations in this pool is the type of surface equipment used. All of the plants are equipped with compressors capable of delivering gas for starting pressures as high as 600 lb. and in some cases to 1,000 lb. Volume-control meters are installed in nearly all cases where gas is being delivered from a high-pressure header to several wells which require different input pressures. Air is used to flow the wells as there is insufficient gas for this purpose. Not all of the gas-lift wells are equipped with meters to measure the well's output gas, although there is a meter on each input well. This, of course, makes it impossible to say just what the net gas-oil ratio is."

"The tubing sizes vary from 2½ to 4 in., depending upon the size of the wells. The gross gas-oil ratio in this pool seems to be very low, the majority of the wells averaging from 700 to 1,100 cu. ft. per barrel. The input casing head pressures on the other hand are rather high, averaging from 150 to 215 lb. Some of the wells making around 400 bbl. have working pressures as high as 175 lb. per square inch."

"The tubing position in these wells in most cases ranges from 250 to as high as 550 ft. off bottom. This is due in part to the high starting pressures off bottom and in other cases it is based upon the supposition that the most efficient tubing position for a gas-lift well is at some critical point which may be anywhere from the top of the pay to a point several hundred feet up the casing. The results in this field show possibilities of long life for the gas lift, if it will be possible to reduce the working pressure against the face of the producing sand as the rock pressure becomes depleted."

Installation of the E. J. Miley Oil Company at Torrance, Calif.

The following data were reported by George Reid:[1]

"Seven oil wells, varying in their daily production figures, are being artificially flowed by gas-lift methods and have been producing oil under this method for practically 2 years. The installation of the gas lift has done away with pumps and pumping equipment, no rods are present on the lease and at most of the seven wells there is no gas engine or other equipment to be utilized for the possible cleaning of the well."

"Often a well flowing under gas-lift methods remains equipped with almost the complete rig, to be employed in the event the gas lift fails, or is to be abandoned for some reason or other, but the Miley lease installation has been so successful and dependable that practically all of such equipment has been removed to some other point of activity. And the life of a string of tubing may be said to be indefinite, rods are eliminated and subsequent rod troubles, nor is there any wear and tear or depreciation on rig and engines, etc., to be figured against the cost of producing the oil from the well."

"Wear and tear or depreciation of mechanical equipment must, however, be estimated as regards the compressor installation required to handle the dry gas which is returned under pressure to the well. Another item of expense though, which can be removed from consideration, is the labor item in maintaining pulling or cleanout crews, for in this installation of gas lift several of the wells have been flowing for 2 full years without any attention given the hole."

"The equipment employed in this seven-well installation consists of three Ingersoll-Rand Imperial steam-driven compressors, high-pressure 6 by 12 in. and low-pressure side 12 by

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[1] Reid, George, Gas Lift Reduces Mechanical Equipment and Attendant Depreciation, *Oil Weekly*, p. 29, Oct. 8, 1926.

12 in. with 9 by 12-in. steam cylinder. These compressors handle dry gas under pressures ranging from 90 to 350 lb., running under governor control, and produce the oil flow from six of the Miley wells. The third compressor, also Ingersoll-Rand, FR 2 is 8 by 4½ by 8 in. and is employed in discharging gas directly to one well."

"The dry gas entering the compressors is scrubbed, increased to 100 lb. pressure on the low side of the machines, then conducted to a water-cooling tower where it is cooled, scrubbed again, and returned to the high side of the compressors. At this stage, the gas is compressed to whatever pressure is required to make the individual well flow, for this installation is operating under the impulse or intermittent system."

"All of the gas from all three compressors is automatically turned into one oil well at a time and permitted to discharge into each particular well for a predetermined period, usually about 3 min. In this way the compressors build up sufficient pressure to flow the well and after flowing, the gas under pressures passes on to the next well to secure like results. For this reason, the compressor speed is regulated by governors."

"Distribution of pressure from one well to another is accomplished by a clock-like contrivance which revolves a dial, pins being placed at intervals which cause electric contacts, which in turn effect the opening of small valves releasing pressure to actuate a trip placed at the manifold on the gas discharge line."

"As soon as the time limit for a certain well is reached, the trip automatically causes a camshaft to revolve a portion of a turn, and in doing so the projecting cams are likewise moved, releasing the tension on the stem on one valve and at the same time opening a second valve by depressing the valve stem. This automatic time regulation accomplishes the direction of the total gas flow from one well to another and at previously determined time periods, as previously mentioned. In this manner, under present practice, each well receives the full discharge of the compressors for approximately 3 min. periods on an average, or each well of the six receives the full volume of gas about once every 18 or 19 min."

"The pressure required to flow the wells varies with each of the six wells handled to some extent. A review of the pressures employed on the day of the writer's visit is about as follows:

Well number	Pressure range, pounds
1	150 to 240
2	145 to 215
3	160 to 225
4	125 to 195
5	140 to 195
6	90 to 190
7	Being flowed direct from the single compressor is handled at pressures ranging from 300 to 400 lb.

"It is estimated that the installation as employed by the company and which was installed by the Loomis Oil Well Control Company working in conjunction with engineers of the Miley Company represents a total cost of approximately $25,000."

"Under this method, the gas is heated to 200° F. and is injected into each well at that temperature. The crude produced leaves the well at about 130° F. and the gas leaving the well is naturally about the same temperature."

"At the time of the installation of the gas lift, the production of the lease was around 600 bbl. of 19 gravity oil daily and with the completion of the gas-lift work the lease gradually climbed in production to over 900 bbl. daily and hung around this figure for some months. Later, it took a normal and gradual decline and now, after about 2 years of flowing under artificial methods, the production remains around 500 bbl. daily and, due to the fact that for several weeks the production has been at this figure, it is thought that the property has settled to a normal production at which figure it will stand for some months to come."

"It is estimated that the total of four compressors are using about 1,750,000 cu. ft. of gas daily which is injected into the wells. The gas now returns wet. Gas from this section of the Torrance field has never been of high gasoline content, the usual recovery before gas-lift installation having been about 0.6 gal. per 1,000 ft. of gas. Gas, however, after its return trip to the bottom of the hole is taken to a near-by absorption plant where, it is said, the content of gasoline is increased to 0.9 gal. per 1,000 ft."

"Where dry gas is injected into the oil well under the impulse systems under conditions as described above, it is possibly of interest to know how the operation is checked at the individual well."

"Figure 159 is the chart record of one well of the six operating or flowing under this intermittent type of gas-flow system. At each well there is placed either a Foxboro pressure recording instrument or a Tycos instrument of similar operation principle whereon is recorded for permanent reference and record the action of pressure as applied to the well during each 24-hr. period. Note on this chart that at 8 a.m. the well has just begun to flow at a pressure of 200 lb. and continued to flow under decreasing pressure for about 15 min. and that during the next 3 min. the pressure was building up again toward another peak where flowing was resumed."

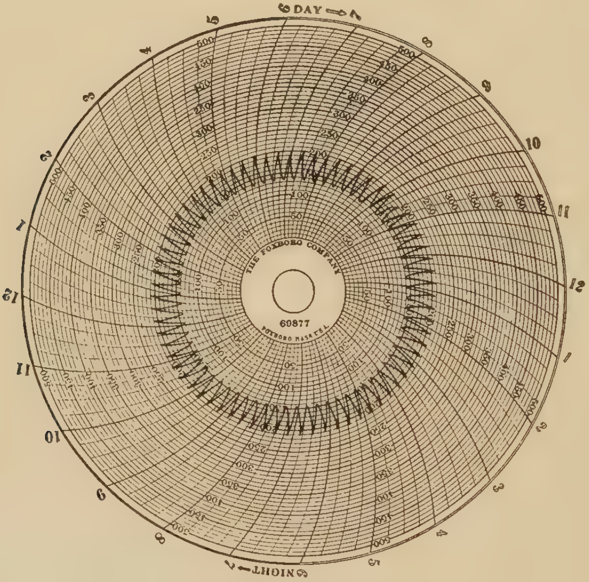

Fig. 159.—Chart made by one of the six wells flowing under gas pressure. (*Reid.*)

"The automatic control of the compressors in diverting the gas from well to well has caused the return of the dry gas to this particular well, building the pressure up gradually until it flows again, then to pass on to the next well in the before mentioned sequence, but to return to the well in question after a predetermined period of about 18 min."

"It is claimed for this installation of gas lift that not only has the company been enabled to secure more oil per well than neighboring producers employing other methods but that they have also produced more oil per acre from their lease, and, since the installation of the impulse system of gas lift, at a very much lower figure of cost per barrel."

The Chanslor Canfield Midway Oil Company Installation in the Torrance Field, Calif.

"George Reid[1] described their installation as follows:

"In the Torrance field some interesting work is also being done by various companies. E. J. Miley, Sentinel, Petroleum Securities, Chanslor-Canfield Midway Oil Company and others are installing gas-lift systems and are meeting with success as the usual thing."

"The C.C.M.O. Company has installed a three-compressor plant so manifolded that five wells will be handled from one installation."

"As an experiment, before it was decided to make this full-sized installation, two compressors were installed to operate on two separate wells. The compressors used on these two wells, each compressor working as a separate unit on a separate well are Ingersoll-Rand, Imperial Type 5½ by 12, electrically driven by General Electric 75-hp. motors. One well is operated or flowed under about 150 lb. pressure, and the other at about 200 lb. pressure. These pressures are lower than those usually found in practice elsewhere."

"The production of each well was increased over 60 per cent, and as the gas production was also increased and the gas enriched in gasoline content, it has been found that these two installations paid themselves out in increased volume and richness of natural gas alone in a very few weeks. A casual inspection of the equipment employed in the flowing of these wells reveals that very satisfactory results have been obtained and that the money expended per well is much less than $5,000. Deduct from that figure certain items of maintenance, equipment, etc., taken from the rig for use elsewhere, and the venture becomes more profitable than before. In this particular installation it is said that the daily yield of gasoline alone as mentioned above is of sufficient value to defray the operating expense of the well;

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[1] Reid, George, California Operators Spend Large Sums Experimenting with Gas Lift, *Oil Weekly*, p. 28, Oct. 1, 1926.

thus the crude oil produced is considered as net profit from the operations."

"The usual results secured where the experiment culminates in the successful flowing at any particular well is a slight decrease in the A.P.I. gravity of the crude oil, varying from 0.5 to 1° A.P.I. This decrease in gravity and corresponding decrease in the gasoline yield from the crude is almost invariably offset by the enhanced value of the natural gas yielded, both in volume and in richness. In addition, the condition of crude petroleum previously high in percentage of cut (B.S. etc.) is usually remarkably improved under certain methods, some installations reducing the cut from 30 per cent to less than 1 per cent."

Throughout practically all of the fields of California the producing companies are rapidly turning to conservation plants, employing practically the same methods and principles and differing only in the type of equipment adapted to the procedure and in the type of flow devices placed in the well, some employing the patented devices offered for the purpose and others employing no such devices whatever; the results are as variable in successful exploitation as are the brands of equipment employed.

Installation of Union Oil at Richfield, Calif.

The following summary is extracted from the description by W. E. Green:[1]

"The system that has been perfected by the Union Oil Company has resulted in a most successful centralized control of a large number of wells, great economy in labor operations, centralization of power, and greatly increased efficiency."

"One of the outstanding results obtained by the Union officials at one well is the case of that company's Brooks No. 2 in the old Huntington Beach field. This well was pumping 110 bbl. a day in May, 1925, and when placed on the gas lift June 1, 1925, the production was increased to 675 bbl. a day from that date to May 31, 1926. From June 1, 1926, to date this well has averaged 1,150 bbl. daily through 6¼-in. oil string. The depth of this well is 4,500 ft."

"The Union has 93 wells operating with the gas lift. Three of the systems are operating in fields in what the Union terms the

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[1] Green, W. E., Installs Central Plant to Apply Gas Lift on Wells, *Nat. Petroleum News*, p. 51, Oct. 20, 1926.

'Los Angeles district,' while the other three systems are in the Orange district. The accompanying table lists number of wells operated from each plant, with the daily production of each group of wells:

Field	Number of wells	Total daily production, barrels
Orange district:		
Richfield	15	4,200
Huntington Beach	8	1,800
Brea Canyon	8	2,600
Totals	31	8,600
Los Angeles district:		
Santa Fe Springs	22	8,000
Dominguez	15	9,000
Rosecrans	25	5,200
Totals	62	22,200
Grand Totals	93	30,800

"According to the American Petroleum Institute figures for last August, the total of 367 producing wells in Huntington Beach produced at the average daily rate of 120.9 bbl., against 225 bbl. daily for the wells operated by the Union on the gas lift. At Richfield, the total number of producers in August produced a daily average of 91.3 bbl. against 280 bbl. per well on the gas lift."

"In the Los Angeles district, the total of 348 producers in August at Santa Fe Springs averaged 139 bbl. against 363.6 bbl. daily on the gas lift. In the Dominguez field, the total wells on production averaged 300.7 bbl. to the well in August against 600 bbl. a day per well on gas lift. At Rosecrans, the August average well production for the field was 105.4 bbl. per day, against 208 bbl. daily from the 25 wells on the gas lift."

"The gas-oil ratio has been reduced in the gas-lift wells in all fields where the gas lift is in operation from an average of 1,850 cu. ft. of gas per barrel of oil produced to 1,200 cu. ft. per barrel of oil, while in the Richfield district the production has been from 1,500 cu. ft. per barrel of oil to 1,000 cu. ft. of gas to a barrel of oil. This indicates a big step toward the conservation of the petroleum resources by effecting this economy in the gas production per barrel of oil."

"The Richfield plant was placed in operation the latter part of April, 1926, starting with 10 wells, with the other 5 being added very shortly thereafter. This installation was completed and in operation 5 weeks after construction work started."

"The system as shown on the flow sheet [Fig. 160], forms a closed circuit of wet and dry gas, alternately compressed and expanded, as it does the work of lifting the oil to the surface."

"The dry gas leaving the absorption plant is compressed in the high-pressure compressor plant. The compressed gas is delivered to the distributing header where the volume and pressure required at each individual well is controlled. From the distributing header, individual lines run to each well in the system. In the normal procedure the high-pressure gas is admitted to the well between the tubing and oil string. It is pumped down the well and enters the tubing at the bottom, lifting the oil to the surface."

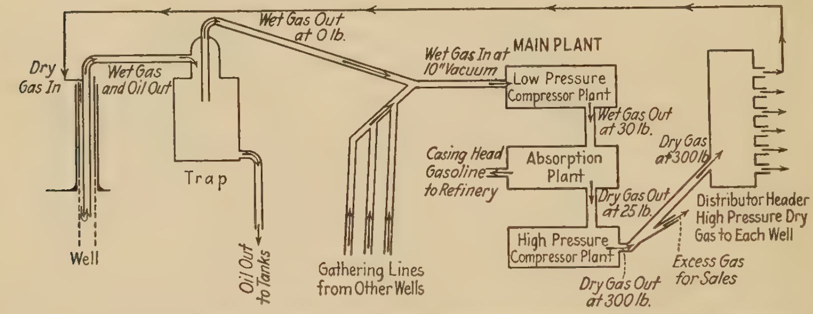
Dry Gas In
Wet Gas and Oil Out
Wet Gas Out at 0 lb.
Wet Gas In at 10" Vacuum
MAIN PLANT
Low Pressure Compressor Plant
Wet Gas Out at 30 lb.
Dry Gas at 300 lb.
Casing Head Gasoline to Refinery
Absorption Plant
Trap
Dry Gas Out at 25 lb.
Distributor Header High Pressure Dry Gas to Each Well
High Pressure Compressor Plant
Excess Gas for Sales
Well
Oil Out to Tanks
Gathering Lines from Other Wells
Dry Gas Out at 300 lb.

Fig. 160.—Typical gas lift compressor and gasoline extraction plant flow diagram.

"The oil and gas are then separated in a gas trap where the oil flows to the gaging tanks while the wet gas enters the gathering system. The wet gas is pulled in from the wells through the low-pressure compressor plant, which discharges the wet gas into the absorption plant. In the absorption plant the casing-head gasoline is extracted from the gas and the dry gas delivered to the intake of the high-pressure compressor plant, thus completing the gas circuit."

"The high-pressure compressor plant in the Richfield district consists of 19 70 hp. Broderick return tubular boilers using gas as fuel, connected through equalizing headers to 19 Chicago Pneumatic single-cylinder direct-connected compressors. Of the 19 compressors, 12 are 10 × 10 × 10 in. used in compressing the gas from 25 to 135 lb. Two are 10 × 7 × 10 in. used in compressing the gas from 25 to 135 lb. Five are 10 × 7 × 10 in. and are used in compressing the gas from 130 to 300 lb., delivering the high-pressure gas from the plant. There is one 10 × 6 × 10-in. compressor used as a booster or starting compressor for kicking over the wells."

"The distributing header consists of two main 8-in. lines with 3-in. individual lines to the wells. The distributing header is equipped with Westcott recording meters which show the actual volume and pressure of the gas delivered to each well at all times. Some of the wells served are approximately 1 mile from the plant, although most of the wells are nearer. Distance of the well from the plant makes no difference in the operation."

"The gathering system for bringing the wet gas from the well traps to the low-pressure compressor plant consists of 4-in. and 6-in. individual lines to the 16-in. mains."

"At the well, no flow device at the bottom of the tubing is used. The size and depth of the tubing in conjunction with the amount of gas circulated are the controlling features in the success of the operation. Tubing sizes vary from 1¼ to 6¼ in. in the wells in the Orange district."

"Gas volume circulated varies from 100,000 to as high as 1,500,000 cu. ft. per well per day. The total volume circulated from the Richfield plant approximates 8,000,000 cu. ft. daily. The gasoline yield averages about 1¾ gal. to the 1,000 cu. ft. of gas. The gas production from the wells runs close to 12,000-000 cu. ft. daily, thus about 4,000,000 cu. ft. daily is produced from the sand."

"Before the gas lift was applied, the 15 wells at Richfield averaged 175 bbl. of oil daily, or a total daily production of 2,625 bbl. After being placed on the gas lift, these wells averaged 350 bbl. daily, or a total daily production of 5,250 bbl., which in a 6-month period has dropped to 4,200 barrels daily, the present production."

"In the erection of the gas-lift central plants, fire protection has not been lost sight of. At convenient points about the plant, small, individual, Foamite tanks have been placed in enclosures, easy to reach in an emergency. By the side of each of the Foamite tanks, there is a high-pressure water hydrant."

SOME WELLS IN THE SANTA FE SPRINGS AND HUNTINGTON BEACH FIELDS, CALIF.

Some very interesting data[1] are furnished concerning a well that was recompleted in the Meyer zone in the Santa Fe Springs field.

"This well was completed at a depth of 4,635 ft. with a 4¾-in. oil string. The well was bailed and swabbed and induced to flow, but each time it was turned into the lead line the flow ceased. After 3 days, the gas lift was installed and the average production for the next 3 days was 800 bbl. per day. During this time the input gas was entering at a pressure of approximately 220 lb. and the back pressure on the lead line and trap was 37 lb. The flow was then turned into a gas trap elevated 25 ft. above the derrick floor. This eliminated the necessity of the flow passing through 600 ft. of 3-in. line, including 11 L's leading to a gas trap elevated above the lease tanks. This change resulted in an increase in the oil production of over 400 bbl. per day. The new working pressure dropped from 220 to 197 lb. and the back pressure on the lead line from 37 to 13 lb. A similar change in the lead line on a well in the Huntington Beach field resulted in a 50 per cent increase in the production."

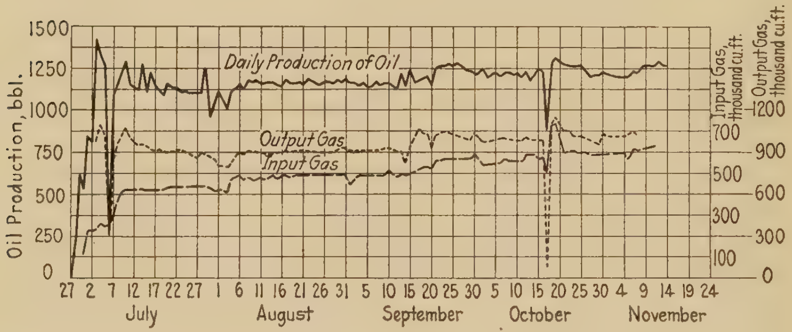

FIG. 161.

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[1] ROBERTSON, GLENN D., and McDOWELL GRAVES, Gas-oil Ratio Reduced by Gas Lift in Some California Fields, *Oil Weekly*, p. 62, Dec. 10, 1926.

"Figure 161 shows the daily production of oil together with the input and output of gas from the Santa Fe Springs well. The production of oil has increased slightly during the 4½ months that the well has been on the compressor. There has also been a slight increase in the gas output so that the ratio between the oil and gas coming from the well has remained about constant. The input of gas has been continually increasing at a faster rate than the output, resulting in an increase in the efficiency in the use of the gas from the sands. On July 20 there were 426 cu. ft. of gas taken from the sand for each barrel of oil, whereas on Nov. 7 there were only 363 cu. ft. taken from the sand for each barrel of oil. The total gas required to lift each barrel of oil on July 20 was 782 cu. ft. and on Nov. 7 was 857 cu. ft. Although the quantity of gas required to lift the oil has increased, this increase has been supplied by the compressor permitting a conservation of the gas associated with the oil in the sand."

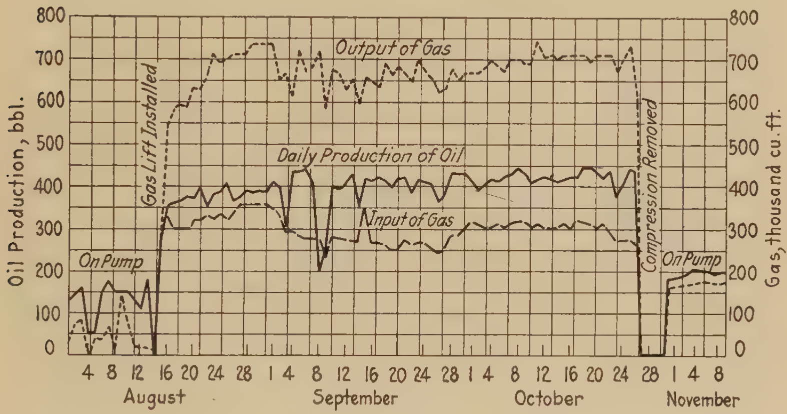

FIG. 162.

"Figure 162 shows the effect of the gas lift upon a well in the Huntington Beach field. A summary of the results of the first 30 days following the installation of the gas lift is briefly as follows:

	Barrels	
Average daily production on compressor	371	
Average daily production for previous month	121	
Increase due to compressor	250	
250 bbl. less one-sixth royalty at $1.44 per barrel		$291.00
	Thousand cubic feet	
Daily gas output while on compressor	733	
Daily gas output for previous month	50	
Increase in output	683	
683,000 at 1.44 gallon of gasoline per 1,000 cubic feet, gallons	983	
Less 10 per cent losses in plant, gallons	885	
Less lessor's interest (35 per cent minus royalty), gallons	258	
258 gal. at $0.13 per gal		34.00
	Thousand cubic feet	
Daily average output of gas	733	
Daily average input of gas	346	
Daily gas production while on compressor	387	
Daily gas production for previous month	50	
Increase due to compressor	337	
337,000 cu. ft. at $0.10 per 1,000 (less royalty)		28.00
Total daily increase due to gas lift		$353.00

"The foregoing clearly demonstrates that for this particular well the gas lift was a profitable means of producing the well. A consideration of the gas-oil ratio during the test and also before and after indicates that for the area in general the gas lift may not have been so beneficial. Prior to the test when the well was on the pump, 322 cu. ft. of gas were produced with each barrel of oil. While the well was operating with the gas lift, an average of 875 cu. ft. of gas was produced with each barrel of oil. After the well was taken off the compressor and again placed on the pump, an average of 884 cu. ft. of gas was produced with each barrel of oil. The production of oil by pumping after the well had been on the gas lift was better than before although it required much more gas to bring the oil into the well from the sands."

"These two wells show no decline, but rather show an increase in production of oil during the time they were being operated by the gas lift. This condition is quite common for many wells in the Los Angeles Basin. However, many pumping wells act in a similar manner for several months after they are first placed on the pump. Production data on several wells show that they have a normal decline and that sooner or later the production will fall to a point where it is advantageous to take the wells off the gas lift and pump them in the regular manner."

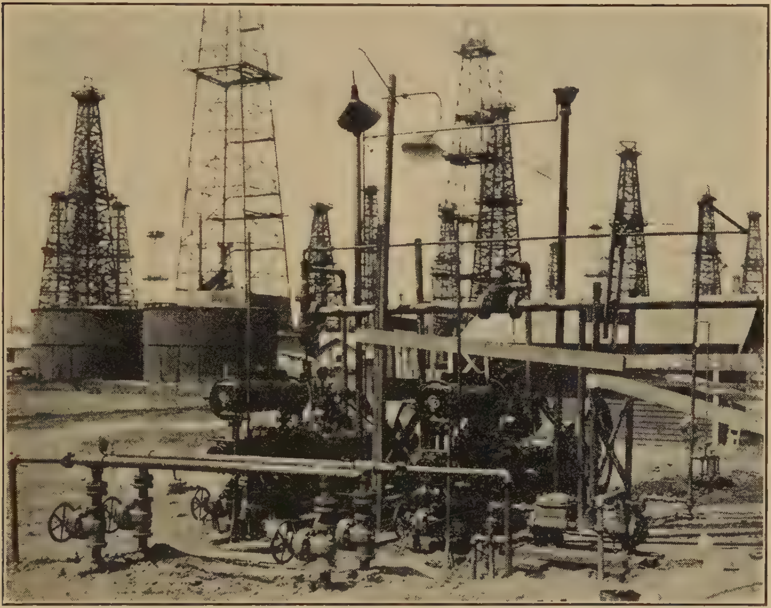

FIG. 163.—Gas lift plant operation at General Petroleum Corp's Twin Bell lease in the Santa Fe Springs field, California. It serves two wells. Two two-stage 10" × 14" × 10" steam driven units especially built for gas lift work, are used. (*National Petroleum News.*)

THE ROXANA'S OPERATIONS IN THE UDALL FIELD, KAN.

"One writer[1] described these operations as follows:

"The field under discussion is northeast of Oxford, Kans., and of the Rainbow Bend pool. It is a development of 1926, the first well having been brought in early in the summer. Production is found in a sand the identity of which is still under discussion. Average depth to the top of the sand is around 1,830 ft. and the pay zone at around 1,860 ft. The pay, averaging about 30 ft. thick, is a fairly tight formation. Wells drilled by the Roxana, Wentz Oil, Vickers Petroleum, Amerada Petroleum have had initial productions of not more than 500 bbl. natural. After shots they swab 1,000 to 1,200 bbl. in 24 hr. The best ones flow for 3 or 4 hr. after the swab is run. Only one well has flowed before shot."

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[1] SMITH, L. E., Individual Compressors for Each Well Are Part of Gas-lift System, *Nat. Petroleum News*, p. 92, Dec. 15, 1926.

"Obviously, from such preformances, there is little gas pressure to move the oil. It was a choice between installing some form of pumping equipment, swabbing the production, or putting in gas lift. Less oil a day would be recovered by pumping. Comparison of costs between swabbing and gas lift led to installation of the latter."

"Casing practice in this field is to set 8 in. at about 1,600 ft. and to land the 6⅝ on the top of the sand. The wells fill up 700 to 1,200 ft. in fluid when drilled in and they maintain a fairly uniform column of fluid for a long time."

"Gas lift was first applied to No. 1. Rutter well in August. At that time the well was swabbing about 800 bbl. Its production jumped more than 100 per cent in the first 24 hr. that the gas lift was used and at this time (Dec. 1) is making around 1,300 bbl. per day. Performance of other wells in the field has been almost as satisfying at this."

"Because of the greater ease of handling the gas through the gasoline plant when it is delivered steadily and at as nearly a uniform pressure as can be held, it was decided to install a compressor unit for each well. These are, however, centrally located and one building now houses seven of the Chicago Pneumatic straight-line, two-stage 4¼ by 10 units, capable of compressing to 1,000 lb. and with delivery capacity of 240,000 or more cubic feet of gas daily at the usual working pressures in this field of about 150 lb."

"Beginning at the well, equipment for gas lift consists simply of bradenhead connection, tubing, and separator. Tubing is varied to suit the requirements of each well, being usually 3 or 4 in.; it is suspended in the hole through most of the column of fluid and, as a precaution, anchor clamps are used. No footpiece is used."

"At the well one departure from the hook-up used in many fields has been made. This is with respect to location of the separators. Following the recommendation made by S. F. Shaw, San Antonio, the separators are set close to the well, reducing thereby the force necessary to flow the well. Separators used by the Roxana in this field are Trumble type. They are set 10 to 15 ft. from the well head. Flow lines are equipped with by-pass so that in case the separator requires attention, the well can be flowed directly into lease storage."

"Gas lines from the separators are 4 in. and these lead into the main gas gathering lines, which are 6 and 8 in. These big lines connect with two 80 hp. Clark compressors which give the pressure necessary to put the gas through the absorption gasoline plant and deliver the residue gas to the gas-lift plant. The gasoline plant, which is of the semiportable type capable of handling 3,000,000 ft. of gas daily, is ¼ mile from the gas-lift plant."

"At the gas-lift plant, the residue gas from the gasoline plant passes through a scrubber tank and into a header from which the seven units pick it up. When a new well has been added to those flowed by gas it has been the practice to start off at about 500 lb. pressure to give it the initial boost. After this the pressure is cut down to around 150 lb. This is not an exact rule, for like a number of other phases of the system, trial and error method plays some part. No tests have been made by the Roxana in this field as to the pressure on the sand but a workable approximation is made in each well by ascertaining the height of the fluid column, the gravity of the oil, and determining the weight of the column in comparison with an equal column of water. This affords, for practical purposes and within close enough limits, an idea of the pressure on the sand that lifts the column to that height and enables the operator to keep the pressure of the introduced gas below the sand pressure. The Roxana has not yet made any determination of the ratio of gas to oil produced, but meters are now being installed at the wells for this purpose."

Bibliography on Air Lift.—The following are some of the most important references covering the principles of the air or gas lift:

Abrams, H. T., Pumping by Compressed Air, *School Mines Quart.*, vol. 33, pp. 293–311, April, 1912.

Arnold, Ralph, and V. R. Garfias, Methods of Oil Recovery in California, *Bur. Mines Tech. Paper* 70, pp. 14–21, 1914.

Daw, A. and Z., "Compressed Air Power," pp. 261–316, Isaac Pitman, 1920.

Ingersoll-Rand Co., Water Lifted by Compressed Air, Catalog 76, July, 1915.

——, "Oil-well Blowing Handbook," 1927.

Ivens, E. M., "Pumping by Compressed Air," John Wiley & Sons, 1920.

McLaughlin, R. P., and C. A. Waring, Petroleum industry in California, *Calif. Bur. Mines Bull.* 69, 1914.

Paine, P. M. and B. K. Stroud, "Oil Production Methods," pp. 158–160, Western Engineering Pub. Co., San Francisco, 1913.

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Redwood, Boverton, "Treatise on Petroleum," vol. 1, pp. 339–340, London, 1913.

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Rix, E. H., Air-lift Pumping of Fluids, *Oil Industry*, vol. 3, pp. 4–11, June 15, 1910.

——, Baby Air Compressors, *Western Eng.*, vol. 1 p. 251, June, 1912.

Thompson, A. B., "The Oil Fields of Russia," pp. 247–280, London, 1918.

Whealton and Townsend, Inc., "Recovery of Oil by Air and Gas Lift," Tulsa, Okla., 1927.

Conclusions on Air and Gas Lift.—It is of just as much value and importance to the producer of oil to know when it is not practical to use gas-flow methods on his wells as it is for him to know when it would be advantageous. All past installations have not been successful due to many reasons; it has been known to cost the oil operator everything from a sanded-up well to its complete loss, not to mention the numerous wells with their various ailments caused by partially successful experimenters striving to produce oil by gas-flow procedure.

Considering briefly oil well production methods that have met with more or less success heretofore, it is admittedly conceded that no one pump of certain dimensions, stroke, and design, has yet been invented which will give a maximum production from every oil well. Likewise, it is no more reasonable to expect that every oil well will respond to the same degree, or any degree, of production by gas-flow methods, which, like production by any other method, has its individual characteristics to be contended with, and gas-flow methods are, and always will be, far from being a cure-all or a phenomenal success when applied to every oil well.

The terms "success" and "failure" as referred to in the artificial flowing of wells are in themselves misleading, and what one authority may class as a success another may concede to be a failure, so the terms as they are used herein may be so designated.

A well being produced by gas-flow methods is a success when the net revenue, both present and ultimate, derived from the well exceeds the net revenue received on other types of production methods immediately prior to its installation. Numerous times it has happened that a well converted to gas-flow methods is a success, even though less oil was actually produced than formerly or a failure, even though the production was materially increased. In the first case, the following changes were noted: The gasoline content of the natural gas was nearly doubled and without a loss in the gravity of the crude oil; the sand content was reduced from 8 per cent to less than 1 per cent and the well was off production only 15 hr. in 30 days' operation, where previously it averaged 3 days off production out of every month. with the added inconvenience and expense of labor and material,

In the second case, the production of the well was increased a few barrels, the sand content was lowered, but the gas output of the well decreased so rapidly that it was necessary to buy gas in the field to fire the boilers, and it just happened that dry gas in this territory was at a premium and, along with the expense of servicing the well, the net revenue was less than when on the beam.

Due to the uncertainty heretofore surrounding gas-lift activities, the operators in the industry have not been willing, generally, to turn over flowing oil wells to be operated under gas-flow methods. Usually the wells given over to gas-flow activities and procedure were wells that were totally unprofitable and entirely unsatisfactory on other production methods, with the feeling probably, that if the worst happened, they couldn't lose much. In consequence, many of the wells to which compressed gas-flowing systems have been applied are wells which could not be satisfactorily or profitably operated under any other method of production. This attitude gives the gas-flow system the reputation of a "do or die" method or the last resort, when, in reality, its economy of operation, simplicity, and ease of control, etc., should give it first consideration. Where gas-flow systems are understood thoroughly, there is no reason why the artificial flow methods should not be applied to the well while still flowing, for the purpose of maintaining that flow continuously.

CHAPTER XIX

GENERAL CONCLUSIONS ON INCREASING RECOVERY

Ultimate conclusions must be drawn from a practical and common sense viewpoint rather than from a comparison of technical data. The chief reason for this is that no two wells are exactly alike. Sand conditions differ in every well. Rock pressure in the sand varies in different fields and also in different wells in the same field. Saturation of the sand, hydrostatic pressure, volume of gas and location of the well on the structure are factors which vary in every well and which must be considered when comparing various methods of extracting the oil.

Should any person attempt to say that any certain method is better for all wells than any other method, he would immediately establish his own lack of knowledge of the subject. He might show figures to prove his theories, but such figures would very likely not even hold good for the wells on the adjoining leasehold. Each field and each well is its own problem. In most cases where very satisfactory tests have been made of a certain method of flowing, it is more than probable that this particular well was an exceptionally good well to start with and would have shown equally good results with other methods, had they been tried.

As an example of what an oil field can finally come to the following information is quoted.[1] This is not a criticism, for much information that is known and used today was unthought of at the time of the Lima field's big play, but unless advantage is taken of the present processes and future developments along the lines of increasing recovery, similar obituaries will be written on some of the present-day big fields:

"Compressed air, chemical treatment, drilling for deeper pay, close study and cooperative methods to reduce operating costs, all have been tried out, or practiced to some extent in the Lima field of northwestern Ohio, to increase production and lengthen the life of this once great producing territory."

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[1] Smith, L. E., Many Experiments Fail to Increase Yield from Lima, Ohio, Territory, *Nat. Petroleum News*, p. 51, Sept. 8, 1926.

"It would be cheering news to operators there if it could be said that some engineer had brought forth the answer to their problem. If it comes, however, it will probably be something that is at present unknown or at least pretty much in an experimental stage."

"Where the use of artificial means to stimulate recovery has failed in this territory, it does not mean that these methods would fail elsewhere. Underground conditions are different here than in many pools and these artificial means, when they were tried out, were still in a very elementary experimental stage."

"There are in the Trenton rock field of Ohio, the Lima field, somewhere between 14,500 wells estimated by principal operators and the 17,940 reported by the U. S. Bureau of Mines as the number in operation at the close of 1925. The writer's opinion is that the government report probably includes a large number of gas wells. The daily well average for the field is around ⅓ bbl."

"The Lima field produces from the Trenton limestone and that part of the lime which contains the oil is dolomitic; the porosity is determined by the degree of substitution. This is, specifically, the controlling factor of the oil accumulating, the general control being the large anticlinal feature known as the 'Cincinnati Arch.' Such wells probably have no underground communication with other wells. One operator tells of having completely exhausted one of his wells some years ago of both oil and water by operating under partial vacuum. It was 'sucked' dry and never again yielded any oil."

"The condition which would warrant installation of compressor equipment would be the knowledge of area in the lime with good thickness of pay and continuity of the 'sand' to insure that the pressure would affect several wells. It would be no use to put air into a well, if that were the only well that drew from that part of the pay—if it were, in effect, a one-well pool. Never is it known in this field how many wells derive their production from the same reservoir. So, the installation of an air plant would be sheerest guesswork."

"There are two principal reasons why the future of the Lima district is so much gloomier than that of many another eastern field that has been producing for an even greater time. One is the mechanical condition of the wells and the greater expense required to maintain them than in districts where the water troubles are negligible. The other reason, far greater in weight, is that the field does not offer possibilities for increasing production or the life of the field by applying compressed air or other restorative methods. At least such possibilities are limited and require much further study than has been spent on this field to date."

"One of the chief troubles of the field now is inadequate gas supply. Originally, the field was blessed with lots of gas, but it has been exhausted and central powers now are shut down for 1 to 2 and 3 days because there is not enough gas to run the engines."

"There is no better illustration anywhere of the evil times that come upon a field because of early profligacy with its gas supply than the Lima field. Now the operators are jealously hoarding every ounce of gas, where formerly they burned flambeaux anywhere they thought they needed a light; it was otherwise wastefully employed, as well as blown off into the air. Gas engines are connected direct to gas lines to avoid the wastage that might occur around a gasometer. Long ago, the hot-tube method of ignition was abandoned on the engines and practically all the engines in the field today are equipped with Wico ignition systems. Operators cannot afford even to burn the small amount of gas required to keep the hot tube above ignition temperature."

It is understood that during the early part of 1928, the Ohio Oil Company was conducting a thorough repressuring experiment on a block of leases which produce from the Trenton limestone. The results so far have amounted to a large increase in gas production with a continually increasing percentage of air accompanying the gas. The experiment is to be a thorough and final test of the possibilities of the Trenton limestone production responding to this method of increasing recovery of petroleum.

The trend of development and application of methods of increasing recovery are detailed in the report[1] of the American Petroleum Institute's Committee of Eleven which classifies the applications and developments as follows:

"1. To conserve as much gas as possible in the formations, *i.e.*, to keep the ratio of gas to oil produced as low as possible.

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[1] Report of Conservation Committee of A.P.I., *A.P.I. Bull.* 3, Jan. 12, 1928.

"2. To return dry gas from compression and absorption plants back into the oil-gas producing stratum for the purpose of conservation and increased production.

"3. To locate wells with respect to structure so that the gas-oil ratio may be kept as low as possible."

Data That Should Be Considered Prior to Application of Increasing Recovery Methods.—Since the ultimate volume of oil which can be profitably recovered from any area is contingent on the character of the natural expulsive forces underground, the character of these forces should be an influencing factor in the choice and development of suitable production methods. Inasmuch as the dominant natural expulsive forces of the most important oil fields in the Mid-Continent area are due to gas pressure, it follows, from this reasoning, that the most efficient methods to adopt are those in which the smallest volume of gas, consistent with economy, is produced with each barrel of oil.

With these facts in mind then, it is obvious that one essential is to investigate, as soon as put on production, the producing characteristics of the first wells drilled in a field. Experience indicates that field experimental work on wells usually is productive of beneficial results and well justifies any extra expense involved in such work. An article by Wallace Davis[1] which described in detail the method of the Rio Bravo Oil Company for securing and keeping the data on the individual well producing characteristics is quoted here:

"Before experimental work is started, all available information regarding the well should be gathered and given close study. This information should include the drilling history, thickness, and arrangement of productive sands, rock pressures, casing, perforations, and liquid levels. Every field, and indeed, more often, every well has producing characteristics peculiar to itself. Any beneficial results that might be obtained by the adoption of a new method in one field would not always be indicative of results in another field. It is for this reason that every effort should be made to gather information and investigate methods which would assist in overcoming production difficulties and reduce the gas factor in the average well. There are so many variable factors and unforeseen conditions influencing the production of oil from a well that one cannot afford to overlook any reliable index for comparing the efficiency of production methods in use. The gas factor is a reliable index."

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[1] Davis, Wallace, Charted Record Kept of Flowing Wells, *Oil Weekly*, p. 60, Nov. 5, 1926.

The following information should be assembled in convenient form for study and comparison. The list is made comprehensive enough to cover all items that it is believed can have any possible bearing on the proposed installation. It is realized that much of the information will not be available, especially in the older fields.

1. *Prepare Working Map Showing:*

Well locations and numbers.
Structure, preferably contours on the producing sand.
Sand thickness by contours.
Property lines.

These data on a blue-line map, white background, are the most useful in the study of field conditions and yet are not so numerous as to make a map too complicated for any other special purposes desired.

2. *Prepare Graphical Well Logs Showing:*

All formations, their thickness and their characteristics.
Casing, sizes, weights, and where set.
Cementing and other shutoffs.
Occurrence of gas, oil, and water; amount and pressure of each.
Packers, type and where set.
Shooting record.

These well logs should be prepared on standard tracing cloth forms so that all necessary prints can be made for use in preparing structural cross-sections, etc. The logs should be checked back with the drilling records.

3. *Prepare Well Histories.*—These should give the complete record of the well, all events out of the ordinary during its drilling; the cleaning out record; deepening with its results, etc.; water encountered and amount. The histories should include the fluid-level data, that is, the depth of the fluid level when not producing and the elevation at which the fluid can be expected to stand when the well is producing its normal production. This can be ascertained, in some cases, while a well is being swabbed, noting where the swab strikes the fluid after the well has been swabbed down. Also the quantity in barrels of fluid including both water and oil which the well can be expected to produce continuously. Fill-up curves should be prepared.

4. *Production Records.*—These should be recorded graphically for oil, gas, and water, on a weekly or monthly basis, preferably the former. One chart should be used for each well. Similar records for the lease or property and the entire field should be available.

5. *Characteristics of Oil, Gas, and Water*

Oil: gravity, viscosity, temperature, distillation analysis.
Gas: gravity, gasoline content, analysis.
Water: chemical analysis, the recognizable characteristics of the water from each horizon.

6. *Structural Cross-section.*—This should be prepared by using the graphical well logs based on some datum. The section should show all marker horizons, producing formations and the casing in each well.

7. *Surface Map.*—This should show the main topographical features, the oil and gas lines with valves and meters with their sizes and the length of each section marked thereon; the location and numbers of tanks and sizes thereof that composed the flow batteries. Location and size of traps and separators, drips, and regulators.

8. *Geological Map.* —This in case of a faulted field is important; the main data to be shown in all information relative to the faults, their type, dips, strike, throw, etc., along with the surface trace.

9. *Summary.*—A brief summary of the operator's relations with the neighboring lease holders, such as special operating agreements or the possibilities thereof. Also, any information relative to the neighbor's operating methods and policies.

Economic Phase of Increasing Recovery.—Leaving out of consideration the doctrine of the oil industry's duty to the public and analogous propositions, the following discussion will deal with the economic phase of the industry that concerns its ability to make a profit. The discussion will be in the nature of a series of suggestions and not an attempt to cover even the subdivisions by title, let alone the discussion of the subjects themselves.

The industry's profits come from the prices received for its products. If the cost of production, which is used here to cover every expenditure which ultimately enters into the cost of producing oil, is lower than the price received for the production, the profits are positive and the industry is making money. If, on the other hand, the price received for the production is less than the cost of production, the profits are negative and money is being lost. It would, therefore, appear that real profits may be secured either by raising prices or reducing the costs.

It is believed that each company executive in the business is always working upon some phase of the reduction of costs. That subject will not be considered here as an item for discussion except as the application of some of the methods of increasing recovery may affect the item of costs.

Everybody has heard or read about the economic law of *supply and demand* and how, if the supply exceeds the demand, prices drop, and that if the demand exceeds the supply, prices rise. Most oil producers have possibly heard or read of the *bargaining power theory*, or have probably formulated its propositions in their own minds, due to the necessities of their own experiences. The following discussion will conform to the idea that the law of supply and demand is the natural basis for price determination, though the discussion can, at any time, be paraphrased so as to state the same ideas in terms of the bargaining power theory.

Overproduction of oil means an excess supply and, therefore, lower prices. As the demand for this oil is relatively low, an excess exists which goes into storage at current or lower prices. The underproduction of oil means a deficient supply and, therefore, higher prices. In this case, the required excess supply comes out of storage at current or higher prices. If no physical storage existed, the price changes would be immediate and of constant occurrence, but with the physical storage available and acting as a surge chamber to either receive the excess supply or give up the excess demand, these constant price fluctuations are avoided to a controlled extent. The working of this principle can be seen on a minor scale in the practice of entering into private agreements covering certain price differentials based on the posted prices of crude oil, where higher prices, called "premiums," are paid for the more desirable qualities of crudes or for necessary supplies to make up for a deficiency, and the opposite proposition, where producers accept a lower price due either to a lower quality of crude or an excess production which has to be moved.

In many cases, the oil in storage is higher priced than the current production and, therefore, to have to withdraw this oil to augment a deficient current supply means either that prices will be raised or the loss of a certain part of the money invested in the storage oil. Oil which has had to be held in storage in the past for periods up to 2 or 3 years has seldom returned a profit; this period may now be increasing due to less chances of finding new prolific fields as time goes on. But, taken as a whole, oil usually goes into storage at periods of low prices rather than at high prices; then the original cost of the oil plus the accumulated storage charges must be below the market prices of current production for this oil to be withdrawn at a profit. This tends to hold down future higher prices just as the other phase, the running of oil to storage, tends to hold up future lower prices. These results represent the working of this law within the intervals of no major price changes. This proposition runs concurrently with and is not antagonistic to the generally accepted idea that oil going into storage portends price reductions and oil withdrawals from storage means the raising of prices.

In periods of great overproduction of economically uncontrolled production, the major price change will occur first and then the oil will move into storage. If the situation is under some sort of control, either through voluntary agreements or conservation working measures, etc., the oil will probably go to storage at higher prices; that is, before a price change takes place. But either way, the price changes are sudden. The resulting lack of stability in the crude market is reflected throughout the industry.

The effort to control the relation between the supply and the demand by changing the price is not always successful in that even a slight rise in price encourages the bringing back to production of former wells that were costly producers, the application of the newer methods for the increasing of recovery, the initiation of new drilling programs on proved leases and, most important of all, the general wildcatting.

The last mentioned practice has the habit of developing beyond control to the extent of causing, at times, excessive overproduction and consequent price reductions, so that prices may go below the cost of production. This tendency has been increasing with the development of the newer methods of increasing production and the higher recoveries resulting therefrom, as well as the development during the past few years of high initial and sustained production fields. The newer methods of geological prospecting, the improved methods of well drilling and of producing wells, all have a share in the returns of increased production from fewer wells drilled. And, in the past, it would appear that price changes were largely based on knowledge of past rather than estimated future supplies of crude oil.

The *demand* for oil is particularly a cyclic quantity; it varies with the seasons, the weather, and the industrial and agricultural activities. One product is in demand during one season, another product at another season of the year, and so on. But the net result is that, instead of the demand for the different products balancing up throughout a year, they come in peak loads due to the utility, in quantity, of gasoline with the resulting accumulation of the by-products of its manufacture. The seasonal demand for these by-products, when they do occur, do not approach in magnitude the gasoline demand. The price of crude oil and its derivatives has but little effect upon the demand therefor. Consumption appears to go on regardless of the cost, except in a few cases.

The natural unrestricted *supply* of crude oil can hardly be considered as a cyclic quantity in the major sense. It varies over periods, more or less following at intervals of approximately 1 year, and the crude oil price changes. This is particularly true as regards price advances. But the lowering of the price of crude does not have the degree of influence toward reducing existing production that a price rise has in increasing production. The yearly peak of the supply may occur at any time during the year, as shown by curves of past production. It must be noted here that, regardless of the past successes in finding and the development of new and prolific "pools," crude oil is a wasting asset. The underground supply, both that which has been proved that which remains to be found, is exhaustible; it is limited in amount and is not being replaced.

Regardless of any immediate oversupply of petroleum, a relative large percentage of current demand is met from the production of currently flush fields. It is becoming more and more necessary that these prolific sources be found if the demands of the immediate future, which are constantly increasing, are to be met. The trouble in the past has been due to the lack of control of the current supply rather than the existence of an excess supply.

And entering into the question of the supply of oil is the "closing-in" policy extant in certain districts where certain wells or even fields are temporarily shut down, due mainly to the inferior quality of the oil and possibly for other reasons, such as current overproduction. This brings into consideration the difference between what may be called "actual supply" and "potential supply."

A study of the details of the variations in supply, demand, and prices for the period beginning with the year 1920, shows, today, the success in securing new production which followed the prices rises; at the best, only small decreases of production follow the price declines. It became apparent that the manipulation of the price schedule as a method of control of the oil production was not an entire success. The excessive overproduction of the 1923–1924 period caused much comment and thought, but the development of a working means of control was made unnecessary at the time due to the big demand which developed and lasted through the 1925–1926 period. But 1927 brought in another period of overproduction and when drastic price reductions were put into effect, which in many cases changed profits into losses, it was seen that, in order to continue in business, some means of control other than price changing was necessary.

The following tabulated figures show better than words the condition of affairs for the state of Oklahoma alone:

Year	Average price per barrel	Total production barrels	Total value
1926	$2.31	179,200,000	$413,900,000
1927	1.43	277,800,000	397,200,000
Differences	0.88	(+) 98,600,000	(−) 16,700,000

This condition of affairs brought into being the policy of proration or the controlled curtailment of production.

This means of control is the logical method; the supply of oil should be held to such a level that the demand will yield prices which will cover the costs of production plus a fair profit. There is no argument about profits being necessary, and, before profits can be made, costs must be paid. In only this way can economic wastes be avoided. There is always a big waste of crude oil when prices are low, due to its increased use directly as fuel oil.

Statistics show that about 2 per cent of all wells in the United States yield about one-half the total production. Based on this fact, the suggestion has been made by James McIntyre, of the *Oil and Gas Journal* staff, that a permanent policy of conservative production of a relatively small number of flush wells would put the producing industry on its feet and keep it there. It would, in times of potential overproduction, keep the surplus oil in the ground, its natural storage place, and would give the producer and royalty owner a greater ultimate revenue from the sale of the oil produced. It would enable owners of old settled properties on which there are 250,000 small wells to keep their leases up to the highest productive point possible. No one would suffer, and the ultimate consumer need pay little more for the oil products than he is paying at the present. Gasoline would continue to be the cheapest of all commodities.

The basis for and the results obtained from different methods of proration are studies in themselves. Some methods are successful to a marked degree, while some others will probably fail. There is one variable that enters into each method or plan of proration and which, if successfully taken care of, practically means the assured success of that effort. This so-called "variable" is the matter of agreement between operators as to the details of the method.

And here enters the character of the personnel of the oil industry; men who have more or less been "on their own" in practically all of their work have a hard time agreeing to even a compromise of ideas as a working plan or method of proration. No one plan can be devised which is of universal application or which is absolutely equitable to the interests of all the participants. The main point is that, as the interested operators have decided that in order to maintain prices at a profitable level or a level which will at least return the operating costs, production must be curtailed. The plan of proration is, then, the resulting necessary compromise of ideas.

After the plan has been formulated, the next step is to carry out its provisions. The chances of success of the accepted plan depend entirely upon the support given by the individual operators and the interest of all the operators who, through their holdings, should be participants. In some cases, the operator who should be in the agreement will refuse to join. The artificial prices, which will naturally be caused by the provisions of the agreement, will be taken advantage of by these parties to secure higher prices, but prices still below the price which the agreement seeks to maintain as equitable. This will, of course, increase the dissatisfaction, especially of the weaker elements in the agreements and may cause some to disregard the plan altogether.

In some cases, the disgruntled operator will entirely disregard the agreement from the beginning, or if not then, later on, sometimes openly, sometimes evasively. Some particular operators may have markets which will absorb their entire production. Some may have reasons for believing that the general market needs more oil than is being produced or will be produced under the proration agreement. In many cases, the agreement is not observed by a few, which, naturally, causes the remainder of the operators to feel, at least, like "dropping the agreement into the hole."

It is believed that, ultimately, some means will be found for the education of the operator who has entered into the agreement and who stays just so long as it may suit his convenience. Also, some means must be found for the handling of the minority interests of a project, be they the royalty or the operating interests, which sometimes prevent the putting into effect of a plan which is for the good of the whole field. As pointed out by the technical press and trade journals so many times, it will be far better for the industry itself to handle this matter than to have some governmental agency thrust the solution upon the industry.

As stated by W. S. Farish:

"The greatest progress will be made by voluntary action. As I see it, there are three steps necessary to a plan of control. First, we must consolidate all acreage possible on known structures. Next, we must stop financing wildcats on acreage that is not consolidated. Finally, after these measures have been taken and a pool is brought in that threatens to upset the balance, we must prorate, with the help of the state governments."

"If we go on as we have been, we will not have prosperity until there is a shortage of oil which will be from the lack of supply—when the resources have been squandered—and that shortage will be permanent."

Another point of interest is the extent of proration rather than the method. In the past, if an extraordinarily prolific field were developed, the market prices of crude oil were immediately threatened; price reductions impended and the greater the production at lowered costs, resulting from either flush production or production secured by some improved means, the more imminent the general decline of posted prices. In other words, prices are of general interest, while proration has worked only locally. If one district, or, say, a state, restricts production in its most prolific fields, its operators are certain to be dissatisfied if a neighboring state permits a continued excess of production to flood the market without ample control.

The markets for distribution of any oil-producing section of the country are not as well defined today as they formerly were. The process of company integration is constantly going on and results in the larger companies becoming national in scope with regard to their distributive markets. It can hardly be said that any one oil producing section possesses the only rights for marketing in that section. Certain advantages are natural, such as proximity to the areas of consumption, lower freight rates, etc., but the fact that only one well produces oil in one township or county or any other unit of municipal subdivision does not, in itself, make that unit the sole market for that producer, except on the basis of successful commercial competitive practices.

If one area can economically produce enough oil profitably to supply itself and some other areas, at prices lower than those required by other sections, the first section will probably market its oil in these other areas, regardless of the local producers. This has been done in the past and will probably continue to be done in the future. Proration of the first section's production should be initiated if the practice will help to maintain its prices so as to show profits, as well as to help maintain general prices at profitable levels. But on the other hand, the proration of the first section's production in order to allow the second section to compete would hardly be thought of as good practice.

It will be practically impossible for the practice of proration to be instituted for the purpose of maintaining prices at such levels where excessive profits could be made. This is due to the competitive conditions within the industry. Where it is so hard to secure working agreements among different operators which would yield only working profits, it can hardly be conceived that agreements general enough in scope to yield any excessive profits could be made without someone taking advantage of the possibilities of the situation.

The subject of increasing the recovery of petroleum may be considered to deal with two objectives, namely, to obtain oil which, under former methods of production, would probably be left in the reservoirs and to reduce the cost of producing oil.

During periods of underproduction, that is, when consumption exceeds the amount being produced and storage oil is being withdrawn to make up the deficiency, prices are relatively high. Production costs of a normally operated property will change as the production of that property declines, where the declining production has to carry a greater and greater proportion of the property's fixed charges. This state of affairs will demand the production of all possible oil and will cause every effort to be made to secure oil which was formerly thought to be unobtainable. Also, by the reduction of the production or lifting costs, the operating costs will be reduced and the margin of profits will be greater.

But now consider periods of overproduction when the demand has dropped off below what might be considered as the normal production, or when some extraordinarily productive areas have been opened up and are flooding the market; in either case, oil has to be stored with the resulting extra cost of that practice. Prices drop, but even with lower prices no producer, be he the smallest or the largest, wants to close in his production and stop his income, no matter how small it has become. It may be a matter of bread to the former and of only slight embarrassment to the latter, but, regardless of why, the income is necessary, because after money has been put into development costs, oil must be produced and sold in order to secure any returns on the invested capital. And besides, hopes for permanently higher prices at some future time would hardly be a sound basis for deferring production until that happy time arrives.

It would certainly seem foolish, economically, to ask the larger producer to curtail, except in cases of flush production as before mentioned, so as to let the smaller producer proceed with the producing of his oil, unless this practice be based on the principle that the large number of small wells are the so-called "backbone" of the industry's oil supply and should be carried along at whatever the cost. But who is to pay this cost? The producer who has gone to the expense of trying to increase his recovery by the use of the before mentioned methods has increased the ultimate supply of petroleum and made a certain part of the oil that would have been left in the reservoirs available.

Since this is one of the basic principles of *conservation,* he can hardly be asked or forced to close down. This producer has still the competition of the low-cost flush production to meet. Even though the largest producers of the industry were to curtail their production and, theoretically, cause a general price increase, the smaller producer would be "riding along," only at the expense of the larger producer, because the cost to the larger producer would mount, due to the reduced production having to carry the increased proportion of the greater overhead. In other words, to allow the smaller producer to continue, the larger producer must assume the added financial burden. The point is that there must be cooperation, either through a voluntary working agreement, some system of unified control, or integration somewhere along the line.

With continued overproduction and low prices, the holdings of the weaker operators are gradually absorbed by the stronger operators at prices below their real values. This is a matter of history of the immediate past; it should be a factor tending to cause voluntary agreements to be more popular than they appear to be and to cause stricter adherence to the agreements when once entered into. But as a matter of fact, it is not only the so-called "weak" operators who fail to live up to the agreements; the strongest operators are sometimes the worst offenders.

Petroleum deposits not recovered by the present operating methods, normal or improved, constitute a reserve in the sands that will come out through flooding, mining, and whatever other ultimate recovery methods may be developed, whenever flowing and pumping wells are no longer able to meet the demands of consumption and the price of crude oil will allow the necessary returns on the invested capital. The oil industry's one problem and obligation in the development of an oil field, after once having opened the field to development, is to take from the reservoir the greatest possible amount of petroleum.

"True conservation" as defined by S. S. Wyer, "is not hoarding, but the wise use of the natural resources, and it implies not merely the preserving in unimpaired efficiency, but also a wise and equitable exhaustion with a maximum efficiency and minimum waste." As defined by the Committee of Nine, conservation is the drawing on the underground oil resources without waste and in accordance with real demand. This certainly calls for the controlled production of our natural oil and gas resources so as to assure the ultimate recovery of the maximum amounts of the products of each field. It would seem that the expectation of greater personal profits which should result from controlled operations would serve to cause.the voluntary carrying out of all possible proration agreements.

Some authorities take the position that the oil remaining unrecovered in the sands, after being produced to the economical limit by present methods, can later be taken out of the reservoir profitably at such time as the raw material prices can be stabilized on a $4 to $5 per barrel basis. When this time comes, which will probably be as an emergency, the reserves to be exploited by mining and other methods can be assumed to contain far greater quantities of petroleum, though of a much inferior quality, than has already been brought to the surface by flowing and pumping methods.

The point is also made that the industry would not market the residue oils, let alone the crudes, as fuels were crude oil prices stabilized on a $4 to $5 per barrel basis. Nor would the industries now using relatively cheap fuel oil care to consume it against other types of much cheaper fuels, such as coal.

One important aspect of the subject is the fact that due to the ability to exercise any degree of physical control of the amount of oil being produced, up to the maximum available for each well, a certain reserve of petroleum exists which can be produced as and when the market conditions warrant. Former fields can be reestablished and drawn on as needed. If it can be shown that any or all of these methods of increasing recovery are controllable to the extent that no oil need be taken out of its natural storage until economic conditions warrant its extraction, an important advance will have been made in establishing definite reserves, which are frequently spoken of as lacking during periods of excess consumption, as well as establishing an element of stability in the oil industry. This underground reserve of oil would be of far greater value than were it stored above ground.

There are times when several flush fields occur together, causing a drop in the market price of crude oil and affecting most fields where the yield is small. Can such fields be restored as to pressure; shut in when it is unprofitable to produce the oil; produce when the price permits of profit; regulated or controlled to the extent of providing the much needed stability as is experienced by the steel industry, for instance, and, finally, be within the law? It appears to be practicable and probable.

Natural gas, heretofore the most expensive of all the products to handle, proves to be the most important factor in reducing the cost of producing a barrel of oil; if it is utilized to the greatest possible extent for this purpose, commercial users of gas may be obliged to resort to other fuels. Because of the apparently ulimited supply of natural gas available in California at the present time, it is being used for all possible markets and new gas lines are constantly being constructed to open new markets. It is, of course, being used in the fields and pumping stations where available. It is logical to assume that when it is utilized to the fullest possible extent in stimulating oil production and effecting a higher ultimate oil recovery, a considerable part of that supply now entering commercial channels will be diverted from present uses. But this will take place only after the gas which now is going in to the atmosphere has been conserved; the change would be gradual and would depend upon the rapidity with which the producing companies start using gas conservation plants. The diversion of natural gas from commercial channels will undoubtedly result in a proportionate gain in fuel-oil consumption.

The natural desire of everyone connected with the production end of the oil business is to recover the maximum amount of oil possible, but it is realized that an economic balance must be struck whereby the cost of oil recovery is not excessive with respect to the value of the oil recovered. Methods of increasing recovery always add to the total costs but, usually, reduce the per barrel costs due to the increased production.

Any methods that result in bringing more oil to the surface in uncontrolled amounts and without increasing the ultimate yield, are not improving economic conditions. The true gage to the conservation of the nation's oil and gas resources, from a production standpoint, is the effect of production methods upon the utilization of the natural energy as shown by the gas-oil ratio that exists during the productive life of the well. Other things being equal, that method which produces the most oil with the smallest amount of gas most nearly approaches the ideal method which permits the greatest conservation. Conservation of the gas dissolved or otherwise associated with the oil in the sand by the reduction of the gas-oil ratio is the most important consideration and should not be confused with the saving of the gas that is brought to the surface, except in so far as this gas can be returned to the producing formation for the purpose of increasing the ultimate recovery.

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Increasing recovery	I.R.
Repressuring	rep.

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